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DEVELOPMENTS IN PIPELINE TRANSPORTATION OF PETROLEUMS WITH REFERENCE TO REGIONAL REFINING CONSOLIDATION

by

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "Developments in Pipeline Transportation of Petroleums with Reference to Regional Refining Consolidation" submitted by Frank C. Basham in partial fulfilment of the requirements for the degree of Master of Arts.

ABSTRACT

This study evolves and applies an analytic framework to evaluation of the relationship between petroleum pipeline developments and regional refining consolidation.

An analytic base was first developed consisting of the cost structure of pipelines, the nature of long run costs and economies of scale in pipelining. This was supplemented by derivation of the bases of transportation costs of petroleum following from the principles of cost structure. Tariff schedules were examined and their structural property, nonproportionality with distance, explained.

General economic forces bearing on the location of manufacturing industry and specifically petroleum refining and processing were introduced as part of the analytic base.

The analytic base was applied to a recently observed phenomenon in Canada's prairie region refining activity, that of an apparent trend toward consolidation in Edmonton. Factors of significance in the consolidation were classified into necessary and sufficient conditions for consolidation. The conditions examined included economies of scale in operation of the unit processes, raw materials orientation, technological developments in refining processes and environmental requirements. Development of an efficient petroleum products transportation system, the products pipeline, was shown to be the necessary condition for refining consolidation. Further conditions necessary for the emergence of a products pipeline network were examined. These include market

characteristics, status of technology and intermodal transport costs.

The analysis and application confirmed that narrowing transport cost differentials between unprocessed, processed and refined petroleums, and other technological and economic forces affecting petroleum refining and processing location have acted coincidentally to bring about the apparent consolidation trend.

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CHAPTER ONE

INTRODUCTION

This study examines crude petroleum and petroleum products pipeline transportation systems in western Canada within the context of prairie regional refining consolidation. Following a comprehensive analysis of the cost structure and development of pipelines and related petroleum transportation costs, the study proceeds to relate locational forces bearing on refining consolidation to the transportation segment of the petroleum industry.

Setting of the Problem

Rapidly growing demands for energy in the heavily populated and industrialized regions of North America have centred attention on both intensive and extensive development of the continent's most widely used conventional energy sources -- petroleum and natural gas. However, the most significant sources of oil and gas in Canada are some distance removed from the principal energy markets. United States Gulf coast, midwest and eastern supply regions with their gradually dwindling reserves, have accentuated the emerging energy crisis and precipitated interest in the large scale movement of Canadian petroleums to the principal market areas. Canada's main supply areas of the western sedimentary basin, are located in Alberta, northeastern British Columbia, southern Saskatchewan and in a northern extension of the basin through the Mackenzie Valley, Northwest Territories, to the Arctic coastal plain. Since these supplies are landlocked for all practical purposes, and in the latter case, considerable distance from demand centres, overland pipelines,

rail and tank truck offer possible means of transportation.

By volume and value, pipeline systems are the most important mode of transportation for petroleum in Canada. They offer a highly specialized, efficient and reasonably secure service to Canada's major domestic markets (the Prairies, British Columbia's lower mainland, and southern Ontario) and also to major export markets (the United States midwest and Puget Sound). The largest crude carrier alone, Interprovincial Pipe Line Company, accounted for some 63 percent of all crude oil and natural gas liquids produced in Canada in 1971.[1] At present, pipeline networks originating in the Province of Alberta carry crude oil, natural gas, natural gas liquids and refined products to various refining and demand centres. Were it not for the existence of large scale and efficient pipeline transportation systems to these areas, the extraction and development of western Canada's petroleum resources would have proceeded at a pace determined solely by local and regional demands for energy, these latter being of such a limited scale as to have greatly inhibited development in the first place. However, western Canada's petroleum resources did develop in response to a demand for this form of energy at prices sufficiently high so as to encourage both intensive and extensive exploitation of the petroleum resource and to justify development of pipelines.

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[1]Interprovincial Pipe Line Company, Annual Report 1971 (Edmonton: 1972).

Research Objectives

The primary objectives of this study are to present a cost structure for petroleum pipelines and to relate this structure to competitive factors in marketing western Canadian petroleum and petroleum products. These necessarily accommodate as well an examination of the location of refining and distribution activities of the petroleum industry in western Canada. Sub-objectives of the study include the following:

a. To consolidate a theoretical basis from which to view crude and products pipelining, utilizing the analytic tools of location economics and transportation economics.

b. To evaluate the share of pipeline transportation costs pertaining to the marketing of western Canadian crude petroleum and petroleum products.

c. To present a theoretical cost structure for crude petroleum, processed and refined products pipelines transportation.

d. To relate developments in products pipelining to emerging trends in the refining and distribution of petroleums in western Canada. Specifically the phenomenon of refining consolidation is to be examined.

The preceeding statement of objectives reflects the overall organization of the study which evolves as follows. The remainder of the present chapter introduces the reader to the general scope and methodological approach taken and also presents additional technical and background information on pipelines in Canada. Chapter two presents a descriptive synopsis of major existing pipeline networks in Canada pertinent to this study. Chapter three develops theoretical bases for the examination of pipeline transportation costs and refinery location. The relevant theory drawn upon is that of conventional micro-economic cost analysis,

transportation economics and location theory. Chapter four is the main focus of the thesis. It presents necessary and sufficient conditions for prairie regional refinery consolidation. Chapter five summarizes the analysis and postulates the main conclusions and implications of the study.

Scope of the Study

Limitations of both time and data have necessarily restricted the intended scope of the analysis. A complete examination of all petroleum pipelines would include examination of the major trunk line systems (usually larger diameter pipelines of from 16 inch diameter size to 48 inch diameter size) and also the so-called secondary or gathering systems (usually under 16 inch diameter). The latter receive crude petroleum, condensates and natural gas from the field battery or fieldgate and transport these to main trunk line receiving points or to refinery gates. At the present time in Canada, the following types of crude petroleums and processed and refined petroleum products are being transported in varying quantities in pipeline transmission systems in Canada.

1. Unprocessed Petroleums:

   a. Crude petroleum
   b. Raw natural gas

2. Processed Petroleum Products:

   a. natural gas
   b. synthetic crude
   c. liquid petroleum gases (LPG) - propane
      - butane
      - pentanes plus
      - natural gasoline
   d. natural gas liquids (NGL) - a mixture of the liquids in c.

3. Refined Petroleum Products:

a. motor gasolines
b. tractor fuels
c. diesel fuels
d. kerosene and naptha based jet fuels
e. stove oils

This study deals primarily with categories 1 and 3 above namely the transmission of crude petroleums and refined petroleum products. Where data was available or an example for developing a theoretical point was particularly useful, pipelining of one or several of the processed petroleum products is included. Similarly, the study is confined to the major crude and products trunk systems primarily operating in the prairie provinces.

It is beyond the specific scope of this study to examine the economic aspects of field gathering pipeline transmission systems. Under unitization and Alberta's proration plan, operators are paid f.o.b. field-gate for their production. Actual operating costs associated with field gathering systems are judged to be relatively small[2] (expressed as a proportion of field prices for crude oil) as compared to the fixed capital costs for pipe and other transmission equipment which is amortized over the life of the field.

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[2]In a recent Mobil Oil field development installation, some $200,000 in development drilling and completion costs were incurred of which about 10 percent would be associated with the field gathering system. All drilling and completion expenses are capitalized. Interviews with Shell Canada and Mobil Oil confirmed the difficulty of obtaining data on actual gathering operating costs in relation to total field gathering costs (lifting, enhanced recovery and gathering). Capital costs of field gathering systems vary substantially from field to field depending on field size and geological characteristics of the fields.

The scope is similarly restricted to examination of prairie refining capacity only in relation to development of regional products distribution systems.

Methodological Approach

The approach adopted in the study is that the transportation costs associated with petroleum pipelining can be modeled in such a way as to be directly useful in the examination of factors bearing on the competitiveness of petroleum resources in various markets. The importance of understanding the relationship between operating and capital costs on the one hand, and present and possible tariff structures on the other cannot be understated. These central concepts are developed in the study and are directly related to marketing factors for petroleum products in the prairie region. Although the theoretical tools described and developed in Chapter three also permit analysis of other modes of petroleum transportation such as ocean and inland tankers, railway and tank truck, these applications have not been specifically examined even though they would be pertinent to a more complete transportation economics analysis of the competitiveness of Canadian petroleum.[3]

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[3]Comprehensive discussions of the competitiveness of Canadian crude in North American markets and the role of transportation are given in internal reports of the Alberta Energy Resources Conservation Board and some of the major integrated oil companies. Unpublished sources include Alberta, Energy Resources Conservation Board, "Alberta Crude Oil Competitive Position," (Calgary: March 1972); and Foster Economic Consultants, The Prospective Demand for Canadian Crude Under Alternative Industry and Canada-United States Government Policies, (Calgary: October, 1969). One published source is United States, National Petroleum Council, U.S. Energy Outlook: An Initial Appraisal 1971 - 1985, Vol. I, II, (Washington, D.C.: 1971).

Other possible methodological approaches to economic analysis of the pipeline industry and its relationship to regional refining and marketing could have been adopted. One of particular interest in the context of this study would have been the nature of vertical integration in petroleum transportation and marketing elements of the industry. Examination of the regulatory framework relating to the economic character of common carrier transportation systems and, in the case of natural gas, public utilities regulation is another approach. These alternative approaches will only be utilized to the extent that they contribute to an understanding of the dynamic aspects of the problem at hand which is to examine the cost structure and other pertinent economic operating features of petroleum pipelining in a regional refining and marketing context.

Pertinent Characteristics of Pipeline Transportation Systems

Before proceeding into a detailed description of the Canadian pipeline networks, it is useful to identify a few common features of pipeline transportation systems which have characterized their extensive use in the United States and Canada.

Firstly, pipelines are distinguished from other modes of transport in that they offer continuous movement of the commodity. Only a limited range of commodities can be transported although technological developments and the costs of competing modes have somewhat extended the range of feasible products in recent years.[4] Although rigid in routings and

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[4]Applications of pipelining to the transportation of such solids as coal, pulp, and sulphur have been investigated by a number of agencies. (Cont'd)

capacity (in the short run), under optimum loading conditions and with appropriate commodities, pipelines are one of the cheapest forms of land transportation of petroleum and petroleum products, sometimes even competing effectively with water transport. Actual operating costs of pipelines, upon which these intermodel competitive factors are based, are determined by several variables which are discussed in more detail in Chapter three. These variables include throughput volume, pipe size, operating pressure and pumping efficiency, the cost of capital, nature of the terrain and the physical properties of the particular crude petroleum or product[5]. With specific reference to Canada, these variables are of substantial importance.

The principal interregional pipeline carriers for both crude oil and natural gas, have expended millions of dollars in "big-inch"(usually over 16 inches outside diameter) pipeline networks. Capital invested in compressors, pump stations, equipment and pipe represents a far greater proportion of average total costs of a pipeline industry than the actual operating costs (see Table 1). As a consequence, the cost of the capital needed to finance these expenditures is of crucial importance in determining the feasibility of new investments or expansions to existing systems.

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[4]Continued...The Research Council of Alberta's efforts in this respect are noted. See for example: E. J. Jensen and H. S. Ellis, "Pipelines," Scientific American, Vol. 26, No. 1, (1967), pp. 62-72; and E. J. Jensen and J. G. Bruce, "Capsule Pipelining - a feasibility assessment," paper given at 1st International Conference on Hydraulic Transport of Solids in Pipes, Warwick, England, (Sept. 1970).

[5]Gerald Manners, "The Petroleum Revolution", Geography, Vol. 47, (1962), p. 156.

TABLE 1

FIXED AND VARIABLE COSTS OF
OIL TRANSPORT MEDIA

	Fixed (percent)	Variable (percent)	Operating Costs (cents per 100 ton kilometers)
Ocean Tanker	20	80	5.1
Barge	30	70	n.a.
Product Pipeline	75	25	27.8
Crude Pipeline	65	35	21.5
Railway Tank car	5	95	105.6
Truck	15	85	382.8

Sources: Gerald Manners, "The Pipeline Revolution", Geography, Vol. 47 (1962), p. 158. [original source is H. N. Emerson, "Oil Transportation Preferences -- Their Bases", Proceedings, American Petroleum Institute, Section V, (1957)p. 22.]; and Gerald Manners, The Geography of Energy, (London: Hutchinson University Press, 1964), p. 70.

Achieving lower cost transport of petroleum in pipelines is critically dependent on attaining cost savings through economies of scale. The determinants of scale economies are identified and evaluated in later chapters but for now it is sufficient to mention only the importance of relatively high load factors (average throughput to peak demand or optimum line capacity). These are important in interregional petroleum pipeline systems which are of the larger diameter size.

Finally, the variability of Canada's geography with such contrasting features as the Rocky Mountain Range, adverse winter climate, permafrost, and extensive water bodies has greatly affected the ability to generalize about transportation costs of petroleum pipeline systems. Prairie pipeline construction and operating costs, for example, are likely to be considerably lower than those through the Rocky Mountains, Coast Range, or the sensitive Arctic tundra. Terrain variations, therefore, affect the accuracy of simulations of cost structure since each particular host environment imposes a unique set of technological, economic and perhaps social or political limitations.

CHAPTER TWO

SYSTEM CHARACTERISTICS AND NETWORK DESCRIPTIONS

The first part of this chapter is concerned with identifying pipeline system characteristics peculiar to the transmission of crude oil, natural gas liquids or processed products, refined petroleum products and natural gas. The latter commodity is included briefly primarily for completeness and since it is a petroleum resource product which has been further processed from its raw state to a higher valued, end or intermediate use product. The second part of the chapter describes pipeline networks and systems representative of the above commodity breakdowns. In this context, a network is meant to mean the pattern or complex of gathering and trunk lines transporting the particular commodity group (eg. crude oil gathering and trunk lines). A pipeline system means a specific operator's complex of gathering and trunk lines including the related operating infrastructure for all or any of the aforementioned commodity groups.

System Characteristics

Components of a Pipeline Liquids Systems

A simplified petroleum liquids pipeline system is comprised of receiving tanks for storage, various receiving stations, pumping facilities, control, communications and monitoring equipment, buried coated steel pipe, and terminal storage and distribution facilities at the destination. Crude petroleum and other liquids are pumped through a pipeline either directly from connecting points with other pipeline systems (ga-

thering systems, for example) or from tank storage facilities at various receiving points. The importance of adequate storage facilities lies in the need to maintain throughputs at close to the existing throughput capacity configuration otherwise optimal utilization of the installed capacity of pumps and pipe sizes will not be realized. Batching of different streams of crude oil and products pumped through a line also affects its optimal operation since it is less costly to handle only one commodity at a constant rate than to handle several different batches of commodities. Adequate reserves of the different batches in storage tanks will nonetheless insure that the dispatcher can keep the line as full as possible at all times by drawing down on storage reserves when shipments from other pipeline carriers are not being handled.

Most liquid petroleum pipelines carry several separate streams of crude oil or products each having its own particular API gravity, viscosity and corrosive properties depending on the nature of source field and depth of the reservoir in question, or the type of product from processing or refining operations. Interprovincial Pipe Line Company, for example, handled as many as 34 separate streams in 1971[1]. With the possibility that several separate streams could be filling the line at any one time, it would be necessary to monitor the properties of each stream in the line displacing relatively compatible streams in sequence, while discerning the interfaces[2] at the receiving end of the line. These are

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[1]Interprovincial Pipe Line Company, 1971 Annual Report, (Edmonton: 1972), p. 9.

[2]An "interface", in pipeline terminology, means the part of two (Cont'd)

achieved through various kinds of semi-automatic monitoring and control systems or computers and a reliable communications network.

In respect to the available methods of moving crude oil through a pipeline, most companies in Canada with the larger diameter pipes in service (over 16 inch) now utilize centrifugal pumps with electric power motors and/or diesel engines fueled by natural gas or condensate. Pumping stations are located every 40 to 150 miles depending on the terrain, line capacity, planned throughput volumes and pipe diameters. As an approximation, though, and for a given volume, the distance between pressure boosting points will vary inversely with the diameter of the pipe[3]; that is, the larger the pipe diameter, and consequently the larger the potential throughput, the shorter will be the distance between pumping stations. Actual pumping pressures are related to a number of variables (some mentioned above), but in contrast to vapour phase natural gas lines which permit only limited pressure drops between compressor stations, crude oil and liquids lines will tolerate substantial pressure drops

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[2]Continued...separate streams of commodity which is co-mingled at the boundary of the separate streams. Sometimes streams are separated by physical barriers such as floating spheres or by otner buffer materials but where these are not used, the streams tend to mix at the boundary and a blend of product or different crudes results with non-homogeneous gravity properties. The size or amount of the interface depends on the physical and chemical properties of the commodities. Stream separation in the Interprovincial "white products" line is achieved by using condensate or synthetic crude as the buffer material.

[3]J. L. Burke, "Movement of Commodities by Pipeline", in Transportation, United States Papers Prepared for the United Nations Conference on the Application of Science and Technology for the Benefit of the Less Developed Areas, Vol. V, (Washington: U. S. Government Printing Office, 1963), p. 82.

on the incoming side (suction pressure) with discharge pressure at or near maximum operating pressure of the pipeline.[4]

It remains to discuss one final component of a pipeline systems plant and equipment -- the pipe itself. As should be obvious from preceeding discussion, steel pipe is available in a range of diameters. For petroleum liquids systems, the range presently in use is from 2 inch to 40 inch. Planned construction programs in 1972 and later indicate requirements for 48 inch and larger diameter pipe. It suffices to mention here that the important cost parameters for steel pipe, from the pipeline company's point of view, are the diameter required, section lengths and distances to be covered, acceptable pressure tolerances which would affect selection of the wall thickness of the pipe, and working strength of the steel. The potential options available to the purchaser in respect to wall thickness, alloy content (hence weight and cost), diameter, etc. are constrained by the purchaser's financial circumstances, safety and environmental factors and government regulations.

Further detailed descriptions of possible liquid pipeline system configurations and plant and equipment options are not really necessary at this stage of the analysis as the intention was to identify key components affecting operational and capital cost characteristics of most petroleum liquids systems. The cost interrelationships between, say, horsepower, distances, capacities and pipe diameters are discussed in some detail in chapter three of the study. Labour requirements will

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[4]Burke, "Movement of Commodities by Pipeline", p. 85.

also be briefly discussed in chapter three although it will be shown that this is a relatively stable and predictable cost parameter determined basically by the number of pumping stations and the length of the system rather than on other variable parameters.

Natural Gas Pipeline System Components

Natural gas pipeline system components and related costs differ significantly from those of liquids pipeline systems. This follows from the general principles of transmission of vapour phase commodities compared to those of fluids. Transmission of gas in a pipe requires the gas to be compressed to occupy a smaller volume. Fairly stringent controls on temperature are also necessary as gas tends to expand and occupy a greater volume when heated. Since it is desirable to have near capacity volumes of gas transmitted through a line given the yield strength and pressure tolerances of the pipe itself, cooling of the gas to offset heating caused by compression into a smaller volume is therefore necessary. The efficiency of gas pipeline systems are also critically dependent on the characteristics of peak load demands and related pricing. This factor combines with the problem that storage of natural gas[5] at demand points and related inventory controls to obtain a stabilized demand situation,adds substantially to the complexities of simulating a

[5]Liquified storage of natural gas near large demand centers is now quite common. Generally called "Peak Sharing Storage Terminals", they reduce the quantity of natural gas that the pipeline has to move into an area during peak demand periods.

cost structure for gas pipeline systems. Nevertheless, the key differences between gas systems and petroleum liquids systems are the nature of the prime movers (turbine compressors are now being used with increasing frequency), storage phenomena, and the elaborate network or distribution systems to residential, commercial and industrial customers for natural gas. System components that do not differ substantially from liquids systems except in respect to physical and engineering parameters (affecting the magnitude of costs) are the ranges of pipe size in service and kind of pipe construction (eg. Spiral or longitudinal weld), direct pipeline construction costs, labour and administrative requirements. Although not directly related to cost simulation, other differences exist in respect to regulatory and price (ie. tariff) determination. Natural gas systems are regulated by the Energy Resources Conservation Board (field prices, conservation and safety practices), National Energy Board (tariff structures, uniformity of accounting practices, export permits, and rate of return, etc.) and various public utilities boards in the provinces (cost of service and delivered prices, etc.).

Network Descriptions

The remainder of the chapter describes characteristics of the major petroleum pipeline networks originating in the Province of Alberta. They are presented under the following categories based on a commodity breakdown:

a. crude oil pipelines;

b. processed product pipelines (natural gas liquids,condensates, and liquified petroleum gas);

c. refined product pipelines (motor gasolines, diesel fuels, fuel oils, jet fuels, etc.); and

d. natural gas pipelines.

While most conventional data sources[6] distinguish only crude oil, products and natural gas pipelines, this analysis makes a meaningful separation of products lines into refined products lines and processed product lines. The breakdown takes cognizance of emerging trends in the transportation of gas liquids by pipeline. The breakdown also supports one of the basic tenets of the thesis that there is a growing tendency toward transporting a higher valued (and lower weight) commodity in pipelines. This results from the convergence of transport costs for the raw or unprocessed commodity with that of the refined or processed commodity and from economies of scale in refining, processing and transportation. Unfortunately, the form and aggregations of the published data have imposed a limitation on the analysis and much dependence has been placed on personal communication, industry journals, press reports, internal and annual company reports, and data compilations from several published sources.

Pipelines in Canada: Historical Development[7]

Although extensive pipeline development in Canada did not take place

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[6]See for example, Canadian Petroleum Association, Statistical Yearbook 1971, (Calgary: Canadian Petroleum Association, 1972); Oil and Gas Journal, Annual Pipeline Number, (August or September); and Canada, Dominion Bureau of Statistics, Oil Pipe Line Transport, (Ottawa: Queens Printer, annually), Catalogue 55-201.

[7]Most of the historical background is from data given by the Cana-
(Cont'd)

until the early 1950's, some gas pipeline systems were in existence as early as 1904, in Medicine Hat, Alberta (City of Medicine Hat) and 1911 in Southwestern Ontario (Union Gas Company of Canada). The first reported crude oil gathering and trunk system was Gulf Oil Canada's Turner Valley to Calgary line first operated in 1925. Little or no crude oil pipeline construction took place after this until the late 1940's and early 1950's when extensive and simultaneous construction projects were launched by some of the larger pipeline companies presently operating. The major interprovincial crude pipeline networks of the Interprovincial Pipe Line and TransMountain Oil Pipe Line Companies became operational in 1950 and 1953 respectively, offering access to markets in eastern and western Canada, and the United States.

Construction of the first refined products line in Canada, the Canol Project[8], was completed in 1943, from Norman Wells, Northwest Territories to Whitehorse, Yukon Territory and Skagway, Alaska. As a wartime project, this four inch line carried motor gasolines and diesel fuels from the Imperial Oil Enterprises Norman Wells refinery across the Mackenzie Mountains to Whitehorse Yukon and south to Skagway, Alaska for use by Pacific wartime fleets. After the war and following development of a refinery at Whitehorse, the Canol line carried some crude oil from

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[7]Continued...dian Petroleum Association, op. cit., pp. 126-139, where first years of operation of many of the pipelines is given. This is supplemented by reference to the respective companies' Annual Reports.

[8]See for example, R. Finnie, CANOL: The Sub-Arctic Pipeline and refinery project.., (San Francisco: Ryder and Ingram Publishers, 1945).

the Norman Wells-Fort Norman fields to the refinery and some refined product was transported in the Yukon Pipelines Limited line to Skagway. The Norman Wells-Whitehorse portion of the line is now inoperative as is the Whitehorse refinery. Refined product is now transported from Haines and Skagway,Alaska to Whitehorse, Yukon. Other refined products lines in Canada were not developed until 1952 when Trans Northern's system connecting Montreal, Ottawa and Cornwall, and the Imperial Oil Enterprises' Sarnia Products Pipe Line system connecting Sarnia and Greater Toronto became operational.

Processed product lines are of somewhat more recent origins. They followed closely the development and marketing of natural gas in Alberta and the construction and operation of natural gas processing and gas liquids fractionation plants. Imperial Oil's Nisku Products Pipe Line first transported liquified petroleum gases from the Leduc field and processing plant to its Edmonton refinery and terminal in 1954. Recent history has seen the conversion of some crude oil lines in Alberta to processed product lines following the installation of fractionation and processing facilities in the larger gas fields. Participation by some of the regional and national carriers such as Peace River Pipe Line Company and TransCanada Pipelines in the development and operation of the gas plants is also noted.

Crude Oil Pipelines

The major crude oil pipeline systems originating in the Province of Alberta are identified in Table 2. In order to put a reasonable analytic bound on the number of systems discussed, a minimum throughput

TABLE 2

MAJOR[a] CRUDE OIL PIPELINE SYSTEMS ORIGINATING IN ALBERTA

Company	Origin(s)	Destination(s)	Line Diameter(s) (inches)	1971 Aggregate Estimated Capacity(b/d)[b]	1970 Through-put (b)	1970 Aggregate Line Miles
Aurora	Carway, Alta.	Carway, Alta.	8, 12	100,000	18,569,483	1
Bow River	Wrentham, Alta.	Hardisty	4 to 12	34,000	9,284,000	383
Federated	Swan Hills, Alta.	Edmonton	3.5 to 16	281,000	67,166,563	632
G.C.O.S.	Fort McMurray	Edmonton	16	58,000	11,873,420	266
Gulf, Alta.	Hassar field	Edmonton	2.5 to 12.75	73,000	17,668,000	375.5
Home Oil-Cremona	Sundre, Alta.	Calgary	3.5 to 8.5	24,000	6,806,055	154.9
Husky Pipe Line	Hardisty	Lloydminster	6 5/8 8 5/8 10 3/4	12,000 40,000 65,000	1,620,777 2,095,552 9,784,753	217.5
Imperial Pipe Line	Leduc - Woodbend Acheson Golden Spike Excelsior Fairdell	IPL TransMountain Edmonton Terminals	2 to 12	80,000	21,332,900	294.0

Continued

TABLE 2

(CONTINUED)

Company	Origin(s)	Destination(s)	Line Diameter(s) (inches)	1971 Aggregate Estimated Capacity(b/d)[b]	1970 Through-put (b)	1970 Aggregate Line Miles
Interprovincial[c] (IPL)	Edmonton	Port Credit	12,16,18	1,001 M b/d ex Edmonton	332,000,000	5132.0
		Buffalo via Regina	20,24,26 30,34	1,100 M b/d ex Cromer		
		Superior Sarnia		538 M b/d Superior, Sarnia via Mackinaw		
		Chicago				
Mitsue	Nipisi Mitsue	IPL Redwater	2 to 10	20,000	2,491,000	196.0
Peace River	Northwestern, Alta.	Edson Edmonton	2, 3, 4 6,8,12 16,20	115,000 (crude)	40,875,000 (total liquids)	1260.0
Pembina	Pembina area	Edmonton	3, 4, 6 8,10,12,16	180,000	56,714,000	918.8
Rainbow	Zama area	Edmonton	3 to 10 24,20	225,000	47,139,000	623.0

Continued

TABLE 2

(CONTINUED)

Company	Origin(s)	Destination(s)	Line Diameter(s)	1971 Aggregate Estimated Capacity(b/d)[b]	1970 Through put	1970 Aggregate Line Miles
Rainbow (continued	Mitsue	Redwater	2 to 10	20,000	n.a.	--
Texaco-Pipe Line Dept.	Rimbey	Edmonton	2, 3, 4 6, 8,10 12,16	130,000	33,848,700	178.3
Trans Mountain[d]	Edmonton	Kamloops	16,20	310 M b/d ex Edmonton	117,500,000	892.5
		Burnaby	24,30	320 Mb/d ex Edson		
		Port Mann	3	355 Mb/d ex Kamloops		
		Washington State				
Rangeland[e]	Ricinus Joffre Gilbey Wimbourne Sundre Ferrier	Rimbey Sundre	2 to 12	60,000 b/d	13,133,014	415.76
	Pincher Creek	Carway	8, 12	108,000	18,569,483	248.0
	Twining	Rowley	3, 4	7,000	157,499	34.8

Source: based on information in Canadian Petroleum Association, <u>Statistical Yearbook 1971</u>, (Calgary: Canadian Petroleum Association, Sept. 1972), pp. 126-135.

TABLE 2

NOTES

[a]"Major" crude oil systems in the context of this study means those whose aggregate estimated throughput capacity for all lines in the system is in excess of 20,000 barrels per day. This is an arbitrary designation which is specifically intended to exclude the substantial numbers of oil and pipeline companies operating field gathering systems in the Province. Most of the companies listed operate either one or more trunk lines or have some interests in secondary gathering systems (those carrying crude from the field battery to trunk line receiving points).

[b]Aggregate estimated capacity refers to the potential throughput volume in barrels per day of all the lines in a particular company's system under present pumping capacity.

[c]Further details regarding Interprovincial Pipe Line Company's system is provided in Tables 3 and 6.

[d]See also Table 4.

[e]Rangeland Pipe Line Company, a wholly owned subsidiary of Hudson's Bay Oil and Gas, operates an extensive field gathering, secondary gathering and trunk line network in southern Alberta most of which has not been described in the Table. The company is also involved in the transportation of natural gas liquids and condensates from various processing plants. Only data for exclusively crude oil lines is given.

capacity of 20,000 barrels per day was arbitrarily selected below which no specific identification would be made in the table. Above this minimum capacity, the pipeline systems are identified by operator, origin and destination, line sizes in diameter inches, (in most cases outside diameter is given while in others inside diameter is given; neither is distinguished in the data sources), aggregate trunk and gathering line miles, throughput capacity in barrels per calendar day and, latest actual throughput in barrels per day.

As was mentioned briefly in chapter one, crude oil pipeline systems can be further categorized into secondary or gathering systems and trunk line systems. Many of the operators listed in Table 2 are involved with field gathering, direct delivery to refineries and also delivery to interprovincial pipeline receiving stations. Generally speaking though, field gathering and secondary systems are defined to be those which have maximum pipe diameters less than 16 inches or line throughput capacities less than 20,000 barrels per day, and which delivery to receiving stations of the regional trunk lines, or interprovincial trunk lines. By comparison, trunk pipeline systems are defined as those with throughput capacity in excess of 20,000 barrels per day and line diameters in excess of 16 inches. It is necessary to point out that the secondary and trunk line categorizations chosen here apply only to crude oil lines since for processed and refined product systems the criteria are different.

The companies listed in the table operated about 12,223 aggregate line miles of which about 2,699 miles was gathering line and 9,524 miles trunk line. The line diameters in operation in 1970 ranged from 3 inch

to 34 inch. Looping of 48 inch line has recently been approved for parts of the Interprovincial Pipe Line system by the National Energy Board; this will be the largest diameter oil line in use in North America. In terms of available capacity and also deliveries, this Company's system is the largest in Canada with a 1972 capacity of 1,251 thousand barrels per day out of Edmonton and 1,308 thousand barrels per day out of Cromer, Manitoba. Total 1971 deliveries averaged 977,350 barrels per day. (See Table 3 for the Company's planned 1972 capacity). Trans Mountain Oil Pipe Line Company's system from Edmonton to Vancouver and Anacortes, Washington is the second largest crude oil system with a 1972 capacity of 380,000 barrels per day out of Edmonton. Actual deliveries averaged 332,416 barrels per day in 1971 and throughputs were expected to reach present pumping capacity in 1972 with completion of Atlantic Richfield Company's new Cherry Point, Washington refinery. The Company has National Energy Board approval to expand its pumping capacity to 600,000 barrels per day[9], nearing the design capacity of the existing pipeline.

Interprovincial and Trans Mountain are the most important carriers of crude oil outside the Province of Alberta to national and international markets. An examination of the disposition of Canadian crude oil sales, from Table 5, reveals that the two carriers transported nearly 91 percent of all Canadian crude oil sold in domestic and United States

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[9]Trans Mountain Oil Pipe Line Company, 1971 Annual Report, (Vancouver: 1972), p. 4ff.

TABLE 3

INTERPROVINCIAL PIPE LINE COMPANY
PLANNED AVERAGE SYSTEM CAPACITY BY QUARTERS, 1972
(MB/D)

Sections	I	II	III	IV	Yearly Average[a]
Edmonton-Regina (ex Kerrobert)					
Line 1	126.0	127.0	130.0	127.0	127.0
Line 2	143.0	146.0	150.0	146.0	146.0
Line 3[b]	880.0	890.0	917.0	890.0	890.0
Total	1149.0	1163.0	1197.0	1163.0	1163.0
Regina-Cromer					
Line 1	101.0	108.0	112.0	108.1	108.0
Line 2	167.0	170.0	177.0	170.0	170.0
Line 3	880.0	890.0	927.0	890.0	890.0
Total	1148.0	1168.0	1216.0	1168.0	1168.0
Cromer-Gretna					
Line 1	122.0	124.0	125.0	124.0	124.0
Line 2	278.0	294.0	318.0	294.0	294.0
Line 3	880.0	890.0	936.0	890.0	890.0
Total	1280.0	1308.0	1379.0	1308.0	1308.0

Continued

TABLE 3
(CONTINUED)

Sections	I	II	III	IV	Yearly Average[a]
Gretna-Clearbrook					
Line 1	122.0	124.0	130.0	124.0	124.0
Line 2	248.0	263.0	282.0	263.0	263.0
Line 3	880.0	890.0	936.0	890.0	890.0
Total	1250.0	1277.0	1348.0	1277.0	1277.0
Clearbrook-Superior					
Line 1	122.0	124.0	130.0	124.0	124.0
Line 2	215.0	225.0	240.0	225.0	225.0
Line 3	880.0	890.0	936.0	890.0	890.0
Total	1217.0	1239.0	1306.0	1239.0	1239.0
Superior-Sarnia via Straight of Mackinaw	536.0	538.0	543.0	538.0	538.0
Superior-Griffith (Ill.)	552.0	566.0	583.0	566.0	566.0
Griffith-Sarnia	282.0	290.0	300.0	290.0	290.0
Sarnia-Port Credit	350.0	355.0	365.0	355.0	355.0
Westover-Buffalo	130.0	133.0	135.0	133.0	133.0

Continued

TABLE 3

NOTES

Source: Interprovincial Pipe Line Company, unpublished company source, from interview with Mr. O. Linton, Manager-Administration, Interprovincial Pipe Line Company, June 9, 1972. The data shows 1972 system yearly average capacities as approved by N.E.B. Orders XO-1-71, AO-1-71, AO-1-XO-1-71, and OC-23.

[a]Rather than showing computed averages over the four quarters, this figure constitutes IPL's "best guess" as to the required yearly average capacity under the company's planned 1972 construction program.

[b]Line 1 carries at present synthetic crude oils (average API gravity about 40°), refined petroleum products, and natural gas liquids. Line 2 carries mixed blend, while Line 3 is referred to as the express line carrying speciality orders direct to eastern destinations. O.T. Linton, Manager-Administration, Interprovincial Pipe Line Co., Interview: June 9, 1972.

TABLE 4

TRANS MOUNTAIN OIL PIPE
LINE COMPANY, OPERATING FEATURES
1969 - 1971

	1969	1970	1971
Crude and NGL Deliveries (b/d)	308,411	333,146	332,419
Total Deliveries (bbl.)	109,294,000	117,605,000	N/A
Average Daily Deliveries (b/d)	308,411	321,461	321,461
Deliveries by Destination (b/d)			
Vancouver Refineries	83,781	95,644	101,186
Washington Refineries	215,654	224,225	217,204
Receipts of Crude by Origin (b/d)			
Edmonton	220,195	247,818	255,296
Edson	28,433	25,083	18,552
Kamloops	50,834	50,668	48,724
Capacity of Line (b/d.)	350,000	350,000	400,000
Barrel-Miles (millions)	67,590	73,780	74,367
Average Length of Haul (miles)	618	627	634

Sources: The Financial Post Corporation Service, Trans Mountain Oil Pipe Line Company, (Toronto: MacLean-Hunter, 1971); Trans Mountain Oil Pipe Line Company, Annual Report 1971, (Vancouver: April 1972); and Trans Mountain Oil Pipe Line Company "General Article", (Vancouver: April 1971), [mimeographed].

TABLE 5

DISPOSITION OF CANADIAN CRUDE AND CONDENSATE 1971
(Sales in barrels per day)

Domestic

British Columbia	129,000
Alberta	120,000
Saskatchewan	56,000
Manitoba	44,000
Ontario	371,000

Export

District	1971	1968	1965
V	220,000	163,000	142,000
IV	70,000	68,000	65,000
II	330,000	214,000	113,000
I	100,000	58,000	27,000

Aggregate Sales

	1971	1968	1965
Domestic	720,000	645,000	571,000
Export	770,000	463,000	295,000
Total	1,490,000	1,108,000	866,000

Canadian Imports
[east of NOP]

1971	1968	1965
659,000 b/d	487,000 b/d	395,000 b/d

Source: Oil and Gas Journal, (April 3, 1972), p. 15.

markets. Of total domestic and export sales averaging 1,490,000 barrels per day in 1971 Interprovincial's throughputs averaged 977,300 barrels per day or 65 percent while Trans Mountain's throughputs averaged 332,416 barrels per day or 26%.

As can be seen from Table 3, the Interprovincial system has three lines from Edmonton to Superior, Wisconsin. There is a 20 inch, 24 inch, and 34 inch line to Regina and Superior as well as some looping of the line. While it may seem more reasonable to have a larger diameter single line in place of the three separate lines, indications are that there was enough volume demand for the specific commodities transported in each operation of three separate lines over the route. Respective capacities and commodities handled by these three lines are given below in Table 6.

TABLE 6

EDMONTON TO REGINA INTERPROVINCIAL PIPE LINE COMPANY CAPACITY[10]

1972

Line	Diameter	Capacity	Commodities
Line 1[11]	20 inch	126,000 b/d	synthetic crude oil refined products, gas liquids, condensate
Line 2	24 inch	143,000 b/d	heavy crudes
Line 3	34 inch	880,000 b/d	lighter crudes (express line to Sarnia)[12]

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[10] Source: O.T. Linton, Manager-Administration, Interprovincial (Cont'd)

[11] Referred to by Interprovincial as the "white line". "White" (Cont'd)

[12] "Express line" in this context means that crude oil deliveries (Cont'd)

This portion of the Company's system is singled out here for special attention as it represents the only common carrier refined and processed products pipeline in Canada in present operation. Also, it is noted that the refined products (primarily from Gulf Oil's new Edmonton refinery) and gas liquids including condensates (from Dome's gas liquids network) are shippped in the same line as synthetic crude petroleum (relatively light gravity) produced from the Great Canadian Oil Sands' Fort McMurray processing plant. Interprovincial's second line from Edmonton carries heavier blend crudes from southeastern Saskatchewan for transport to eastern refining markets. The third line carries the lighter specialty crudes directly to Superior and Sarnia refineries from Edmonton.

There are several major crude oil gathering systems serving the Province's larger oil fields as well as some systems exporting from Alberta directly to the United States Pipeline systems. The largest of the secondary and gathering systems are those of the Federated Pipe Line Company (connecting the Swan Hills field to Edmonton), Peace River

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[10]Continued...Pipe Line Company, Interview, (July 9, 1972).

[11]Continued...generally refers to the colour of the product being transported and is usually considered to include most petroleum liquids except crude. Refined motor gasolines and diesel fuels are usually distinguished by colour additives, red for number one motor gasoline, amber for number two, and purple for tractor fuels, these colours normally being blended in at the refinery gate. Most of the refined motor and diesel fuels are translucent or "white" in their pure refined state, though. Synthetic crude is similarly translucent in colour. Other additives such as lead are blended into the product at the destination since these residues would seriously affect the refining process for other feedstocks in the same line.

[12]Continued...from Edmonton Station are shipped directly to Superior and Sarnia where possible.

Oil Pipe Line Company (northwestern Alberta fields to Edson and Edmonton), Pembina Pipe Line Company (Pembina area to Edmonton), Rainbow Pipe Line Company (Zama Lake area to Edmonton) and Texaco Canada's Rimbey to Edmonton network. These carriers each have 1970 rated capacities in excess of 100,000 barrels per day for their gathering and trunk lines. Other than the two main interprovincial carriers, Trans Mountain and Interprovincial, which also serve export markets, only Hudson's Bay Oil and Gas and Murphy Oil (neither listed in Table 2) operate crude pipelines directly from the Province to the United States pipeline companies connecting at the Alberta-Montana border. Hudson Bay's Rangeland Pipe Line Division gathers crude oil in the southern part of the Province for delivery to its wholly owned subsidiary exporting company, Aurora Pipe Line Company, which operates a short two line system in the Waterton area for delivery to the Continental Pipe Line Company in Montana.

Processed Product Pipelines

When raw gas is extracted from underground reservoirs it is usually necessary to purge the gas of any condensed liquids and non-combustible materials such as water and sulphur prior to its delivery to natural gas pipelines and thence to markets. Natural gas liquids and other materials such as water and sulphur are so extracted in gas processing plants which break the raw gas stream ("sweet" gas if no sulphur compounds are present, "sour" gas if they are and "dry" gas if no liquids are present) into marketable gas liquids, sulphur, residue gas and processed, marketable natural gas. Table 7 presents a breakdown of liquified petroleum gas (LPG) production from processing plants in Canada and also

TABLE 7

GAS PROCESSING PLANTS AND PRODUCTION
1972

	Alta.	B.C.	Ont.	Sask.	Total
Number of Plants	129	6	1	8	144
Gas Capacity (MMcfd)	11,197.7	1492.0	1.0	182.0	12,872.7
Gas Throughput (MMcfd)[a]	8,711.9	1302.7	0.5	100.7	10,115.8
Production: (gal./day)					
Ethane	--	--	--	--	--
Propane	2,455,993	62200	--	88,760	2,606,953
Iso-butane	108,100	12600	--	8,760	129,460
Normal butane	1,486,024	49000	--	30,600	1,565,624
LPG mix	300,840	--	--	--	300,840
Combined gaso./LPG	1,077,783	--	100	16,750	1,094,633
Debutanized Nat. Gas	3,125,640	134825	--	29,395	3,289,860
Other[b]	3,534,460	--	--	225	3,534,685
Total Products	12,088,840	258625	100	174,490	12,522,055

Source: The Oil and Gas Journal, (July 10, 1972) Vol. 70, No. 28, p. 91.

[a]Refers to natural gas output of processing plant. Capacity is the amount of raw gas that the plant can process. Net use of natural gas for production of gas liquids and products is approximately the difference between capacity and throughput.

[b]Comprised mainly of condensates and natural gas liquids (NGL's) mixes not specifically broken down into the various liquified petroleum gases (LPG's).

production of marketable gas by Province for 1972. Alberta has about 87 percent of Canadian gas plant capacity and produces nearly 99 percent of Canadian gas liquids production. Marketable natural gas is delivered to gathering and trunk lines while the various liquids are either stored in tanks for distribution by rail or truck, or pipeline. This section is primarily concerned with pipeline distribution of NGL's and LPG's (in general terms, referred to as gas liquids).

Table 8 presents relevant data on most of Canada's refined products and gas liquids pipelines. Refined product pipelines to several of the larger airports (eg. Vancouver, Montreal and Toronto) carrying jet fuels from refineries have been omitted from the table due to lack of data on these systems. The table identifies the operating company, ownership status, line characteristics and also other pertinent information.

Gas liquids pipe line systems have somewhat different operating and cost characteristics from crude pipeline systems. The principal differences are related to the lower viscosity and gravity of products as compared to crude oils. Pumping and horsepower requirements are less than for equivalent volumes of crude oil thus permitting the use of smaller diameter pipe. In the transmission of crude oil by pipeline, for example, the smaller the pipe surface contacted per barrel of throughput the lower will be the friction created per barrel and thus pumping costs will be reduced. In gas liquids pipelines, the components of the pipeline system are similar but there are more stringent requirements in respect to product cleanliness, control of operating pressures (reduced allowable pressure drops between pumping stations), and more accurate batch dispatching and monitoring equipment. Thus, while direct

TABLE 8

CANADIAN PRODUCTS PIPE LINE SYSTEMS
1971

	Ownership	Origin(s)	Destination(s)	Length of Line (miles)	size	Capacity b/d	Source/Type of Product	Latest Throughput	Remarks
Alberta Products Pipe[a] Line Co.	Gulf, I.O.L. Texaco, Shell	Edmonton	Calgary	193	10"	25,000	Gulf Edmonton refined gasoline diesel fuels	15,000 b/d	currently used by Gulf only -1 pumping station at Edmonton, 1 planned for Red Deer. 4 ultimate. 50,000 b/d 1973 capacity
Dome Petroleum	Dome 50% Amoco 50%	Cochrane, Alberta	Edmonton	210	8"	16,000	Cochrane Extraction Plant NGL's, other gas plants enroute	n.a.	From Edmonton to Sarnia via IPL for fractionation
	Dome 100%	Grenfell, Sask.	Melville, Sask.	45	3")	32,000	Purchased NGL's		from Petroleum Transmission Company line
		Empress, Alta.	Kerrobert, Sask.	95	8")				
Goliad Oil and Gas		Pembina, Alta.	Breton	19	6 5/8"	14,000	Pembina LPG and gasoline from plant	1,301	propane, butanes, natural gasoline to Alberta and export
Crean River Exploration	Texaco	Bonnie Glen	Calmar, Alta.	15	4.5"	5,720	Bonnie Glen LPG	n.a.	U.S.A. and Pacific Northwest export
Shawinigan Pipe Line	Gulf Oil 100%	Gulf Refinery P.Q.	Shaw Chemical	12	6 5/8"	16,800	Naptha, distillate	3,138	serving plant
		Shaw Chemical	Union Carb.	12	"	720,000(lbs.)	Ethylene	78,249	serving plant
		Gulf Refinery	Shaw Chemical	12	8 5/8"	--	--	--	line not in use 1970/71

Continued

TABLE 8

CANADIAN PRODUCTS PIPE LINE SYSTEMS
1971
(Continued)

	Ownership	Origin(s)	Destination(s)	Length of Line (miles)	size	Capacity b/d	Source/Type of Product	Latest Throughput	Remarks
Quebec South Shore Products Pipe Line	Imperial Oil 100%	Montreal	Boucherville Drummondville	21 51	10" 8"	34,000	Refinery product Oil, distillates, gasolines	n.a.	-company distribution facility
Nisku Products Pipe Line Co. Ltd.	Imperial Oil 100%	Leduc and Devon processing plants	Edmonton	21 23.6 21.5 21.5 14.25 10.25	4" 3" 2" 2" 8" 6"	6,500 3,100 900 1,000 14,000	Butane Pentane) Pentane) Pentane) Propane)	1,226.4 90.3 2,149.7	refinery, marketing and chemical plants in Edmonton area
Petroleum Transmission Company[b]	Pacific Petroleum 100%	Empress, Alta.	Winnipeg, Man.	578	6 5/8"	14,500	Empress gas plant LPG's: propane, butane	5,300	for distribution in Sask., Man., Ont. and Quebec
Rimbey Pipe Line Company	Gulf, et. al.	Rimbey Gas Plant	Edmonton Terminals	71.5	3 1/2" 8 5/8"	37,000	LPG's (propane, butane)	11,196	for Texaco, Gulf, IOL refineries, IPL and Transmountain lines
Sarnia Products Pipe Line	Imperial	Sarnia	Toronto-Hamilton areas	170	12"	98,000	refined products	n.a.	private company carrier
Sun-Canadian Pipe Line Company	Sun Oil (55%) Shell (45%)	Sarnia	Toronto area	24	8"	30,000	refined products of Sun, Shell Sarnia refineries	n.a.	

Continued

TABLE 8

CANADIAN PRODUCTS PIPE LINE SYSTEMS
1971
(Continued)

	Ownership	Origin(s)	Destination(s)	Length of Line (Miles)	size	Capacity b/d	Source/Type of Product	Latest Throughput	Remarks
Trans-Northern Pipe Line Company[c]	Gulf Shell Texaco	Clarkson Port Credit Oakville	Toronto, Hamilton Port Hope Belleville Kingston	257	10"	75,000	refined products Toronto	n.a.	Ontario markets of owners served
		Montreal	Ottawa Maitland Cornwall	195	8" 10" 12"	72,000	refined products Montreal	n.a.	
Saskatoon Pipe Line Company[d]	Gulf (97%)	Milden, Sask.	Saskatoon	56	6"	15,000	refined products from Gulf Edmonton refinery via IPL	n.a.	destination Gulf Saskatoon terminals Edmonton-Milden via IPL
Interprovincial Pipe Line Company	IOL (33%) Public (42%) Other (25%)	Edmonton	Sarnia	438	20" (Line 1)	127,000 (1972)	refined products, synthetic crude, NGL	n.a.	refined products to Milden and Regina NGL and synthetics to Sarnia
Home Oil Co. Pipeline Division	Home Oil (100%)	connected gas plants	Bowden, Calgary Rangeland P.L.	93.8	2 1/2 to 6 5/8"	18,000	gas processing plants, NGL's (condensate) butane	7,646,329	movements to Bowden, Calgary refineries, export markets
Peace River Oil Pipe Line Company	Misc. oil companies and other	Carson Creek Kaybob Windfall (gas plants)	Edmonton Edson	418	2 to 20"	90,000 (products)	gas processing plants NGL's	n.a.	

Continued

TABLE 8

CANADIAN PRODUCTS PIPE LINE SYSTEMS
1971
(Continued)

	Ownership	Origin(s)	Destination(s)	Length of Line (Miles)	size	Capacity b/d	Source/Type of Product	Latest Throughput	Remarks
Rangeland Pipe Line Division	Hudson's Bay Oil and Gas (100%)	Caroline Sundry Sylvan Lake Gilby Waterton Pincher Creek (gas plants)	various	various distances	2 to 8"	--	NGL's and condensates from gas plants	n.a.	Total 1970 line miles product (NGL's) was 80.7 trunk 90 gathering

TABLE 8

NOTES

Source: based on data given in Canadian Petroleum Association, Statistical Yearbook 1971, (Calgary: Canadian Petroleum Association, September 1972,pp. 138-139.

[a]Alberta Products Pipe Line Company is owned by Gulf, Imperial Oil, Shell, and Texaco for their eventual use in transporting refined petroleum products from Edmonton to Calgary. At present only Gulf Oil Canada is using the line. Gulf is also the operator. The pipeline completed one full years operation near the end of May 1972. Data is for the period May 1971 to May 1972 approximately.

[b]Pacific Petroleums' LPG's transported through its wholly owned line, Petroleum Transmission Company, are distributed to seven terminals along the line. Processed liquid product (LPG) is extracted from TransCanada's natural gas stream at Empress, Alberta and marketable natural gas returned to the TCPL line while liquid product enters Petroleum Transmission's line to Winnipeg. TCPL is being paid for the product extracted and will eventually receive 50 percent of the Empress plant's operating profits once Pacific has recovered capital costs for the plant and pipeline.

[c]In 1963, Trans Northern's system flow was reversed following recommendations in Canada's National Oil Policy. After this date, products of the Montreal refineries, utilizing imported crude oil feedstock, would be marketed in the area east of the Ottawa Valley (NOP line). Consequently, Trans Northern's system is a closed system with flows of product east from Toronto to Kingston and west from Montreal to Cornwall and Ottawa.

[d]This line was originally shipping crude to Gulf's Saskatoon, Saskatchewan refinery but has subsequently been converted to refined product movements for Terminal storage and distribution at Saskatoon. Gulf's Moose Jaw refinery is now producing only asphalt as is the company's Calgary refinery.

horsepower pumping costs for LPG's and other products may be smaller per barrel of throughput than for equivalent crude oil pumping, the lower costs are offset by higher initial cost in equipment and controls and also in a requirement for controlled minimum operating pressure (so the product does not vaporize).

Pipeline distribution systems for LPG's are at present confined to Alberta with only two lines, those operated by the Petroleum Transmission Company, and Interprovincial Pipe Line Company, connecting Alberta with other provinces. The network of gas liquids pipelines in Alberta connect the gas processing plants producing gas liquids to refineries and terminals in Edmonton and Calgary. There are 129 gas plants in the Province although all are not producing liquids (see Table 7). The Petroleum Transmission Company gas liquids line connects the Empress Gas Plant with terminals in Regina and Winnipeg; the system is largely used for the distribution of propane although some other LPG's are carried. Interprovincial Pipe Line Company also carries unfractionated natural gas liquids on a common carrier basis from its Edmonton and Kerrobert Saskatchewan receiving stations directly to Sarnia for further processing and fractionation into liquified petroleum gases. Interprovincial's receipts of gas liquids at Edmonton and Kerrobert to date have come exclusively from Dome Petroleum's extensive gas liquids gathering system in Alberta (including liquids received from Peace River Pipe Line) and from Dome's purchased liquids from the Empress gas plant for delivery to the latter Company's Sarnia fractionation plant.

There are some limited direct exports out of Canada (Alberta to the United States) of natural gas liquids at the present time and also

some limited movements from Dome's Sarnia fractionation plant to refiners and petrochemical just across the United States border. Applications and statements of intent to the Energy Resources Conservation Board of Alberta and the National Energy Board for removal and export of natural gas liquids, specifically ethane, have been filed by several groups. Dome Petroleum's application to the National Energy Board[13] in 1972 for the export of ethane and other liquids calls for the construction of a 2,000 mile gas liquids line from Edmonton to Green Springs, Ohio. At a hearing convened to review the application, a neutral intervention was tabled by a group called the "White Products Pipe Line Study Group" comprised of several producing, distributing and refining companies.[14] The intervention stated the intention of the group to apply to the N.E.B. for permission to construct a natural gas liquids and refined products pipeline to follow a similar routing as that proposed by the Dome application. Propanes, butanes and condensates would be transported to a point near Minneapolis, Minnesota while refined products would be delivered to bulk terminals in Saskatoon, Regina, Brandon and Winnipeg.

Refined Products Pipelines

Table 8 also includes a listing of seven operators of refined pro-

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[13] Financial Post Corporation Service, Dome Petroleum Limited, (Toronto: MacLean-Hunter Publishing Co., 1972), p. 2.

[14] Canadian Superior Oil, Chevron Standard Oil, Gulf Oil Canada, Hudson's Bay Oil and Gas, Kaneb Pipe Line Company, Pacific Petroleums, Pipe Line Technologists (Canada) Ltd., Texaco Canada, Imperial Oil and Trans Northern Pipe Line Company.

ducts pipelines in Canada. The products presently carried in these systems are number one (high octane or premium) and number two (regular) motor gasolines, various grades of diesel fuels, other middle distillates, jet fuels and some fuel oils. These products are in ascending order of specific gravity, the lighter ends listed first and heavier ends, last. By volume the most important products systems are concentrated in the Montreal-Toronto-Sarnia axis linking major refining complexes in the three cities.

Of major interest in these marketing areas has been the effect of the National Oil Policy in forcing the reversal of the Trans Northern Pipe Line's Montreal to Toronto products system in 1963. The system now transports product from Toronto refineries east to Kingston and Prescott, Ontario bulk terminals and from Montreal west to Cornwall with a spur line to Ottawa thus forming, in effect, a closed system having once been an entirely open east to west system. The Trans Northern system distributes product for its owners -- Gulf, Texaco and Shell -- on a private carrier basis. Other products lines extend from the Sarnia refinery complex east to bulk terminals at Hamilton, Toronto, Port Hope and Port Credit, Ontario. The lines in question are Imperial Oil's Sarnia Products Pipe Line and the Sun Canadian Pipe Line. They are private carriers for their own companies' product distribution.

A network of pipeline systems also extends from the Montreal refining complex to various bulk distribution points east of the city and to petrochemical plants in the Greater Montreal area. These are identified in Table 8 as Imperial Oil's Quebec South Shore Products Pipe Line and Gulf Oil's Shawinigan Pipe Line.

In Western Canada, only two systems carry refined products to bulk terminal distribution points and only one of the two carries only refined products. The Interprovincial Pipe Line Company's line one (20 inch) carries refined petroleum products from Edmonton to Regina and one intermediate point via another carrier (to Saskatoon via Gulf's Saskatoon Pipe Line). Although operating as a common carrier, the Interprovincial line is only being used at present by Gulf Canada for distribution of refined products from its new 80,000 barrel per day Edmonton refinery to bulk terminals at Saskatoon and Regina following closure of the Company's refining operations in Saskatoon and Moose Jaw.[15]

Of central interest in this study is the apparent trend toward consolidation of western refining activity in the Edmonton area and servicing prairie petroleum products requirements through a network of products pipelines. The trend has already been observed in the Gulf Oil Canada consolidation in Edmonton and distribution of the Company's product through the Interprovincial system to Regina and through the Company's jointly-owned Alberta Products Pipe Line Company products line from Edmonton to Calgary. This facility, owned by Gulf, Imperial, Shell and Texaco, at present shipping only Gulf refined products to its Calgary bulk terminal following closure of the Gulf Calgary Refinery (Except for asphalt), will eventually be utilized by the other companies. Imperial Oil's planned 140,000 barrel per day Strathcona Refinery at Edmonton will be coming on-stream in 1974 and closure of its older, lower volume plants at Winnipeg, Regina and Calgary is expected. Pro-

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[15]Gulf is still producing asphalt at its Moose Jaw and Calgary refineries.

duct distribution will be through the Alberta Products Pipe Line to Calgary and possibly through the Interprovincial Pipe Line system from Edmonton east through Regina to Cromer, then through a private pipeline to Winnipeg.

The Alberta Products Pipe Line (or APPL line as it is called by the operator, Gulf Oil Canada)[16] has been in operation for about fifteen months. It is presently configured as a 193 mile, 10 inch, 25,000 barrel per day capacity line powered by one 1,250 horsepower, electric motor driving a single centrifugal pumping unit. A second pumping unit is planned for a station at Red Deer in 1973 which will boost capacity to about 50,000 barrels per day. The APPL line pumping and controls station is located just east of Gulf Oil's Edmonton refinery and is presently fed only by two lines (both 12 inch, one for motor gasolines and the other for diesel fuels) from the Gulf refinery. Provision for additional product lines directly from the Imperial Oil and Texaco refineries has been accommodated in the design of station capacity and control systems. Although the Edmonton station houses both the remote control and local station control units for the line, the former could be moved to any location off the line itself.

One of the most important differences between a refined products pipeline and other petroleum liquids pipelines (eg. crude oil, natural gas liquids), is that refined products lines require sophisticated con-

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[16] The information on the Alberta Products Pipe Line system was provided to the writer by Mr. Harold Berg, Products Pipe Line Supervisor for Gulf Oil Canada.

trol and monitoring equipment for reasons of product quality control and safety. The latest available technology for maintaining product quality and line safety has been embodied in the APPL line. A simple device for measuring specific gravity of the product carried in the line is connected to a computerized gravity plotter ensuring constant monitoring and detection of the interface between two types of product. This provides the operator with maximum flexibility in dispatching and receiving uniform quality products. In both the remote control units, computers assist the operator by automatically providing readouts on operating pressures, flow rates, temperatures, etc., at any one of the several metering points along the 193 mile span to Calgary. With these types of monitors, elaborate emerging shutoff valves and storage, and an effective telecommunications system, safety tolerances are maintained at a much higher level than other petroleum liquids systems.

Natural Gas Pipelines

As seen from discussion in an earlier section of this chapter, natural gas pipeline systems differ significantly from petroleum liquids systems. In the interests of completeness, the purpose of this section is to describe in general terms the gathering and trunk lines originating in Alberta omitting any discussion of utility distribution systems originating at the city gate (point where local public utility gas companies purchase gas from the trunk lines). The discussion is intentionally restricted since the central focus of the study is on petroleum liquids systems.

The Alberta Gas Trunk Line Company (AGTL) operates the most exten-

sive trunk facilities, more than 3,400 line miles, within the Province of Alberta for delivery to the major interprovincial carriers - Trans-Canada Pipe Lines, Westcoast Transmission Company and Alberta and Southern Gas Company. These carriers connect with all of Canada east to Quebec plus United States regional lines and distribution systems. AGTL's network links most of the Provinces' major gas fields and receives processed natural gas from secondary or gathering lines or directly from field processing plants. AGTL also exports gas directly to a few United States pipeline companies and indirectly from the Province to U.S. carriers through the Alberta and Southern Gas Company, a gas exporting company. AGTL's 1972 installed, horsepower capacity is about 315,000 while the largest pipe size is 42 inch. Its latest annual throughput was 1.436 trillion cubic feet in 1971. The TransCanada 3,797 mile pipeline system starts at the Alberta-Saskatchewan border where gas is received from AGTL's trunk line near Empress, Alberta and extends east to Toronto and Montreal. Spur lines from the Company's main trunk lines connect with U.S. carriers distributing gas to Minnesota, Wisconsin, Michigan, New York and other eastern states. TransCanada's 1972 installed horsepower capacity is about 857,990 while its latest throughput was 831 billion cubic feet for 1971. Westcoast Transmission Company's 1,000 mile system receives only part of its natural gas supply from Alberta Gas Trunk Line, the remainder coming from gas fields in northern British Columbia.

The importance of introducing natural gas pipelines in this study is to emphasize the potential differences in the cost structure of vapour phase versus petroleum liquids pipelines. The former have higher oper-

ating costs per equivalent BTU of energy transported. One thousand cubic feet (one MCF) of natural gas is equivalent to one million BTU's energy while one barrel of liquified natural gas (LNG), occupying approximately 5.6 cubic feet, is equivalent to above 6.25 million BTU's or about 1,000 times the energy equivalent per unit of volume. This greatly simplifies the actual mechanics of comparing liquid gas lines from their vapour phase counterparts, of course, since feasibility comparisons would usually include analysis of nature of the markets for natural gas, the costs of liquification and regasification, and costs of elaborate safety factors.

CHAPTER THREE

ANALYTIC FRAMEWORK

This chapter reviews and extends the theoretical bases of cost analysis, transportation economics and location theory with specific reference to petroleum pipelines. Although considerable research effort has been allocated to regulatory and competitive aspects of the industry in the literature, particularly in respect to pricing practices (tariffs), competition and integration[1], little has been attempted on the precise nature of costs of various types of petroleum pipelines in relation to overall transportation costs and tariffs.[2] The first and major part of the chapter reviews and extends a framework suitable for analysis of pipeline costs. The framework is then extended to include a discussion of scale economies in pipeline transportation as this complements the cost analysis. A more general transportation economics analysis of tariff rate determination and structure is given. This is followed by a discussion of location theories pertinent to processing and refining petroleum products with particular

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[1]Examples are Leslie Cookenboo Jr., Crude Oil Pipe Lines and Competition in the Oil Industry, (Cambridge, Mass: Harvard University Press, 1955), 177 pp; and J. G. McLean and R. W. Haigh, The Growth of Integrated Oil Companies, (Boston: Harvard Business School, 1954).

[2]Cookenboo's 1954 study on the costs of operating crude oil pipelines remains the only detailed and published contribution of its kind in the field although some subsequent and partial efforts, borrowing from the Cookenboo study, have appeared in industry journals, See Leslie Cookenbo Jr., "The Costs of Operating Crude Oil Pipe Lines", in The Rice Institute Pamphlet, Vol. XLI, No. 1, (April, 1954), pp. 35 - 113.

reference to the development of product pipeline systems. Finally, an introduction to scale economic factors in processing and refining as related to transportation of petroleum and petroleum products is presented. The theoretical review and applications are supplemented by various propositions and hypotheses concerning emerging trends in pipeline systems.

Cost Structure

Conventional practice in micro-economic theory is to distinguish the cost categories listed below for the firm or industry. An industry context is used in this analysis since one could argue from the point of view of the field producer of petroleum that the pipeline company operating the gathering system behaves as a regulated monopsonist and from the point of view of the refiner the pipeline company operating the trunk system behaves as a regulated monopolist.

Short Run Costs

In a pipeline operational sense the conventional notion of short run costs has little relevance. Short run costs, comprised of variable and fixed cost components, illustrated in Figure 1 by AVC and AFC average variable and fixed costs respectively, shows the relationship between average total costs per unit of throughput (in barrels per day), ATC, and increases in throughput from additions to, say, labour and fuel. In pipeline systems, throughput can only be increased above the designed capacity by adding additional pumping equipment, labour and fuel. In a definitional sense the first of these is "fixed" and the latter two are variable in the short run.

FIGURE 1

SHORT RUN COSTS

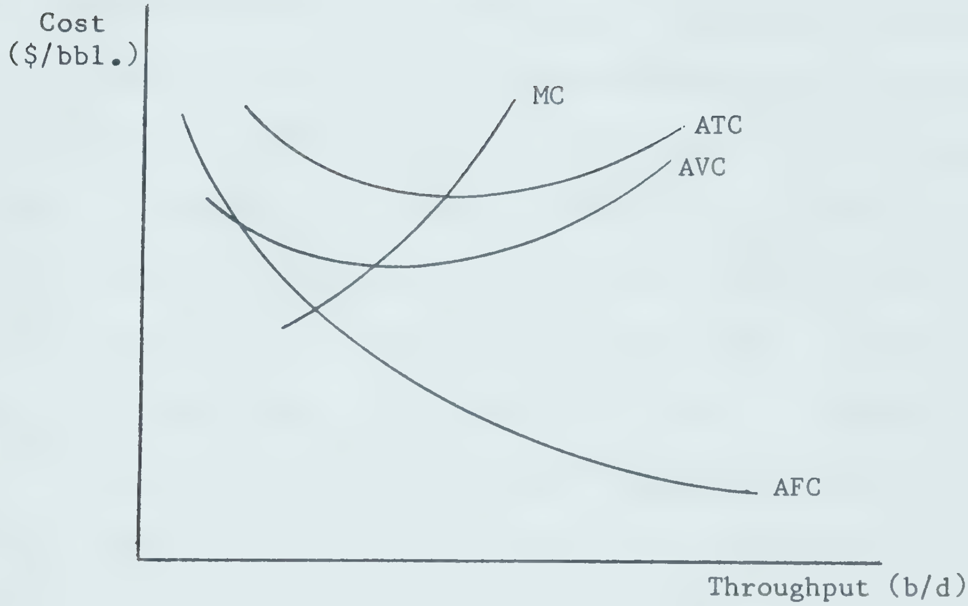
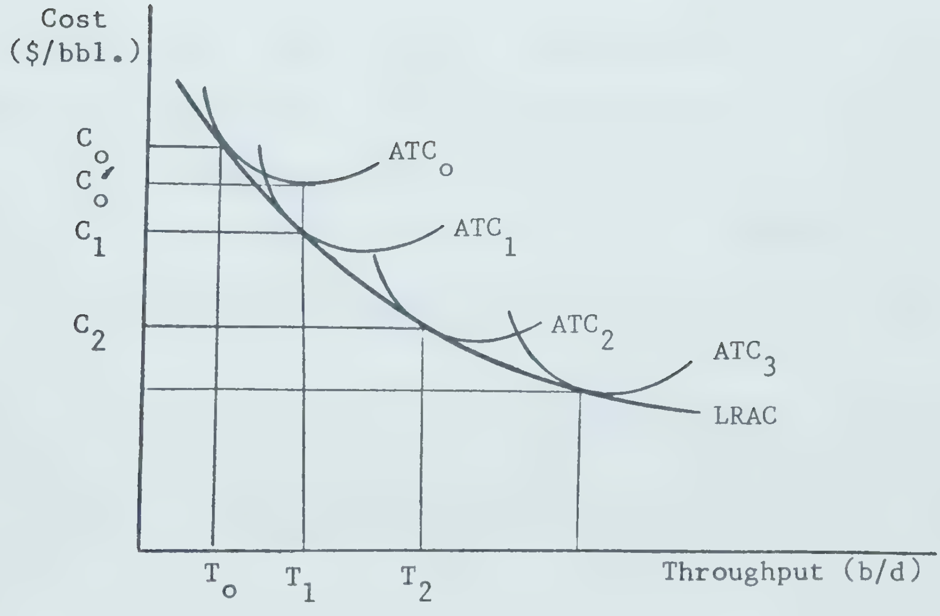


FIGURE 2

INTERMEDIATE AND LONG RUN COSTS



Intermediate Run Costs

Most discussions on cost analysis of pipelines introduce the notion of intermediate run costs at this stage to reconcile the obvious analytic problems introduced by the irrelevance of short run costs in a pipeline context.[3] Intermediate run costs include those which are variable in the short run-- labour and fuel -- and also those which are not reversible such as additions to pumping capacity and horsepower. A cost-throughput relationship is thus derived and illustrated in Figure 2 where the average total cost curves, ATC_i, show how unit costs vary with increasing throughput which in turn result from additional pumping capacity, labour and fuel. The family of average total cost curves, ATC_i, apply to different plant equipment configurations but most important they show cost relationships for different pipe diameters. For a given level of throughput, say T_1 barrels per day, the least cost system configuration would be that represented by ATC_1 which might represent, say, 30 inch diameter pipe. Other configurations using 36 inch (ATC_2) or 24 inch (ATC_o) could conceivably handle the required throughput T_1 but only at higher unit costs of operation.

It is necessary to point out one additional feature of intermediate run costs. Since there is a less than proportionate increase in throughput for a given increase in horsepower, line diameter remaining constant, average costs attributable to power will rise with throughput while those attributable to line diameter which are fixed in the intermediate run, will

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[3]The discussions include Cookenboo (1954), "Costs of Operating Crude Oil Pipelines"; Joseph E. White, "Economics of Large Scale Diameter Pipelines", Pipeline Engineer, (February, 1970) pp. 30 - 34; and Joseph E. White, "Economies of Scale", Oil and Gas Journal, Vol. 67, (January 27, 1969), pp. 149 - 156.

fall with increasing throughput. Thus, for lower levels of throughput average costs will fall gradually from the effect of falling average fixed costs but as additional power is required for higher levels of throughput, costs will gradually rise. This accounts for the characteristic u shape of the intermediate run average total cost curves, ATC_i, in Figure 2.

Long Run Costs

In a pipeline industry context, long run costs refer to the schedule of lowest unit expenditures for given levels of throughput in the range of throughputs under consideration. Declining long run costs are shown in Figure 2 by the darkened line LRAC. LRAC is also called the planning curve since it envelopes the minimum unit cost ranges of the intermediate run cost curves, ATC_i, consistent with minimizing long run average total costs. Even though throughput volume T_1 at a particular time may be sufficient to justify the plant size represented by ATC_o, which, incidentally, would be operating at lowest cost per barrel of throughput at C_o' for that particular size plant, the rational planner would install a plant and equipment configuration represented by ATC_1 thereby yielding lower unit costs C_1. This planning behavior of providing excess capacity in the short run is acceptable providing there are declining long run costs or so-called economies of scale. Discussion in a later section of this chapter indicates that the pipeline industry has enjoyed and will continue to enjoy substantial economies of scale as the larger pipe diameters come into service. This proffers some evidence, then, for a declining LRAC in the figure.

Pipeline Fixed Costs

Fixed costs are defined as those costs which are incurred regardless of the level of production or throughput. Pipeline fixed costs, shown

graphically as AFC in Figure 1, constitute the largest portion of average total costs being approximately 65 to 75 per cent while variable or operating costs comprise some 25 to 35 per cent, on average. For very large systems operating at or near capacity, it is conceivable that fixed expense or overhead items could constitute a smaller proportion than that cited. Other modes of transport have relatively higher proportions attributable to operating or variable expense (see Table 1, p. 9). Pipeline fixed costs are of two kinds: initial costs and recurrent costs. In the former category are included such items as the following:[4]

Fixed Initial Costs:

(a) Right-of-way acquisition, legal and survey costs;

(b) line pipe materials and freight, construction, installation and engineering including valves and fittings;

(c) station materials, construction and installation including station piping, switchgear and meters, etc.;

(d) motors and pumping equipment;

(e) communications systems including telecommunications and/or microwave equipment, data storage and retrieval systems, etc.;

(f) storage tanks and/or looping; and

(g) terminal materials, construction and equipment installation.

In the latter category are included such items as the following:

Fixed Recurrent:

(h) maintenance of line, pumping stations and communications equipment;

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[4]This categorization is used by Cookenboo (1954), "Costs of Operating Crude Oil Pipelines".

(i) line surveillance; and

(j) administrative and insurance expenses.

One of the principle bases of efficiency in the pipeline industry derives from relatively simple hydraulic and geometric properties. Increases in pipe diameter obtain greater than proportionate increases in throughput carrying capacity. In fact, capacity varies as the inside pipe diameter to the power of 2.656. Thus, pipeline system investment in the fixed components identified above decreases rapidly as total capacity and, consequently throughput, increases. This is the basis of the hyperbolic shaped average fixed cost curve, AFC, in Figure 1. Also, since pipeline systems have a high proportion of total costs attributable to the fixed components, operation of the system at or close to design capacity is an obvious objective in order to obtain low unit costs of operation. Selection of the optimal plant and equipment configuration including pipe diameter, wall thickness, pumping pressure and horsepower, station spacing, etc., is discussed in a later section of this chapter. The optimal configuration would determine the magnitude of fixed cost components in a pipeline system operation.

Pipeline Variable Costs

The fixed initial and recurrent cost components discussed above were said to be fixed in relation to throughput volumes although there are interrelationships between some of the items which make them variable with respect to each other. For example, line diameter (hence line pipe) requirements are related to pumping/compression power of a line. This section discusses those cost components which are variable primarily with throughput in barrels per day. It is noted, however, that the time con-

text in which these components are introduced is the intermediate run where irreversible but limited modifications to plant and equipment (such as added horsepower and/or pumping stations, pipe looping, etc.) can be introduced.

The main items to be considered in this variable cost category are system maintenance, direct pipeline labour, and the cost of horsepower.

Firstly, maintenance expense may be treated as being indirectly related to throughput volumes by virtue of the former's association with the actual number and size of pumping stations and distances traversed by the pipeline system. While maintenance expense would not be incurred if there was no petroleum pumped through the line, this expense is less related to the levels of throughput than to the numbers of pumping units and distances. White's estimates for maintenance expense for various system components verify this:

TABLE 9

MAINTENANCE EXPENSE

Stub Lines	$150/mile/year
Trunk Lines	$240/mile/year
Tankage	$0.015/bbl./year
Stations	1.00/bhp/year
Meters	1.00/meter/year

Source: J. E. White (1969), "Economies of Scale", p. 151

Similarly, direct pipeline labour costs, including station supervisors, assistants, operators and casual labour appears to vary more direct-

ly with the number of pipeline pumping stations than with actual throughput levels although in shutdown periods and for limited throughputs labour requirements are minimal. It is important to emphasize here that on a modern pipeline system, there may be only a few manned master pumping stations fully equipped with communications and control equipment capable of remotely operating a greater number of un-manned stations. A typical semi-automatic pumping station would require a daytime station supervisor or chief engineer and one or two operators and two assistants per day shift. If the line is in continuous operation, afternoon and graveyard shifts would be required thereby increasing total labour requirements although fewer personnel are needed on these.

Finally, the most important component of pipeline variable and operational costs is the cost of horsepower. This varies with throughput and a related parameter, pipe diameter. Once the volume of oil to be transported has been determined, and inside pipe diameter is given, horsepower requirements are determined by application of Miller's Formula[5] for hydraulic calculations, yielding a flow rate in barrels per hour which is related to a pre-determined hydraulic horsepower equivalent per barrel of throughput. Hydraulic horsepower is then deflated by efficiency indices for the

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[5]Miller's Formula for hydraulic calculations relates throughput in barrels per hour to inside diameter, pressure drop, specific gravity and viscosity, ie. $T = T\ (P,S,d,Z)$ where

T = throughput in barrels per hour
P = pressure drop psi/mile
S = specific gravity
d = inside pipe diameter (in.)
Z = viscosity in centipoises

See J. E. White (1969), "Economies of Scale", p. 149.

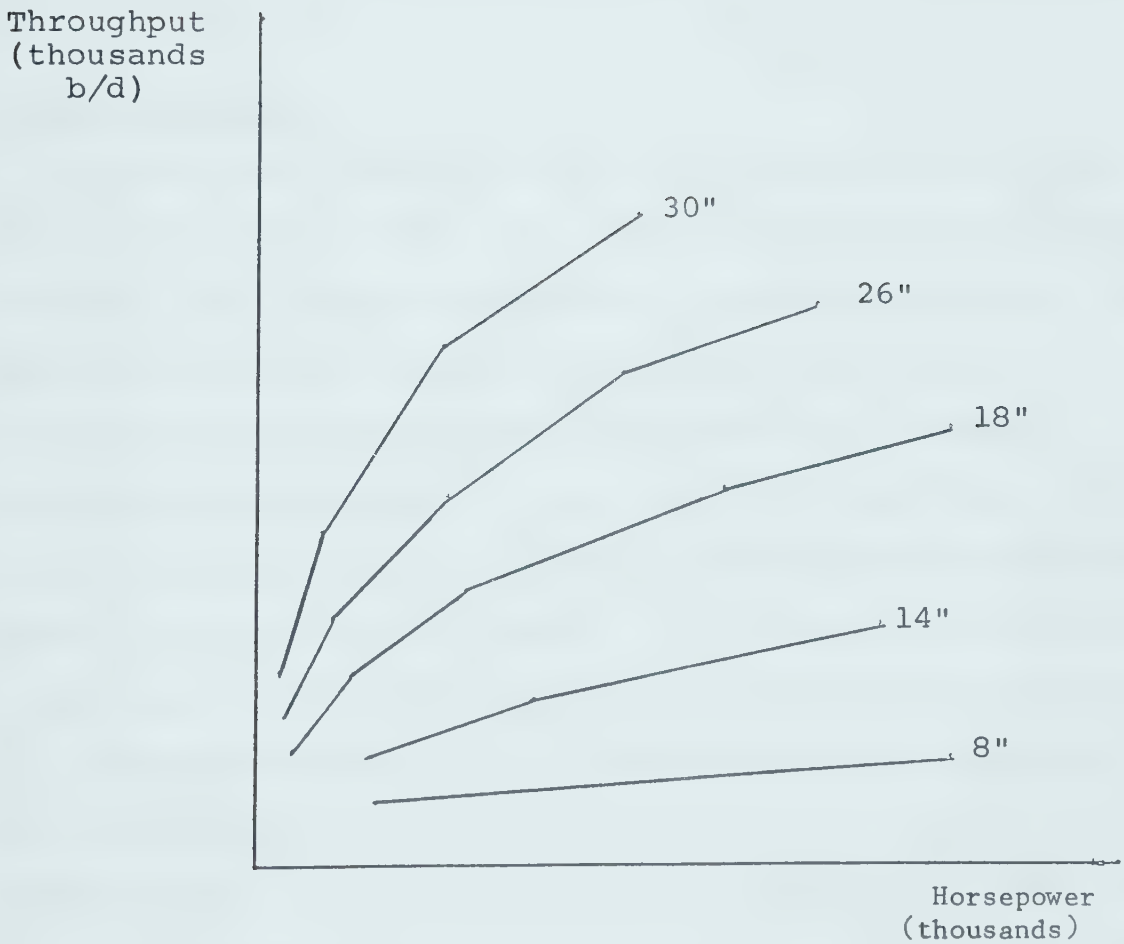
pumps and motors to derive actual horsepower requirements. These relationships are illustrated in Figure 3 which shows a vertical cross section of a pipeline production function, horsepower and throughput as variables with pipe diameter constant. It can be inferred from the figure that for a given plant and equipment configuration, say for a 26 inch pipe system, increased applications of horsepower obtain less than proportionate increases in throughput barrels per day. This implies diminishing returns to horsepower if dollar valuations are used on both axes. The diminishing returns phenomenon is based on the fact that for a given size pipe, larger throughputs induce greater friction and hence greater pumping pressures are required to move the oil.

When pipe diameter is variable in the long run, the friction factor accounts for the fact that greater than proportionate increases in throughput are obtained from application of the same amount of horsepower in a larger diameter line. These characteristics explain the shapes of the production functions in Figure 3, pipe diameter held constant. The curves individually are concave to the origin (decreasing returns) but increase in relative slope with increasing line diameter. In the larger diameter pipe sizes over 18 inches, some increasing returns to horsepower in the lower throughput ranges may result due to insignificant increases in friction. (These latter increasing returns are not illustrated in the figure however since a convex portion in the lower throughput/horsepower ranges would indicate this.)

In the discussion of intermediate run costs earlier in this chapter, it was shown that it is less costly to underutilize a given diameter pipe system than to use the next lower size system to its minimum cost scale.

FIGURE 3

VERTICAL CROSS SECTION OF PIPELINE PRODUCTION FUNCTION



Source: based on Leslie Cockenboo Jr., (1955), Crude Oil Pipelines, p. 16.

(See also Figure 2 where for throughput T_1, the configuration represented by ATC_1 is less costly than that of ATC_0 even though the latter would be used optimally). This implies that on efficiency grounds, any pipeline should be powered originally for a throughput less than the optimal for that particular line size and later, horsepower can be expanded to achieve lower unit costs.[6]

System Optimization

At the planning and design stage of a pipeline system all of the components discussed up to this point and others which have been omitted from discussion are taken into consideration in arriving at an optimal configuration of plant and equipment -- pipe diameter, horsepower, etc. -- for the ranges of throughput volumes expected over time. Cookenboo[7] has simplified the design problem to determination of the least costly combination of the following variables: line diameter, horsepower, wall thickness, safety factor and operating pressure. The theory parallels conventional n-factor production function analysis whereby each factor is utilized up to a point where the value of its marginal contribution to production equals its marginal factor cost or factor price. Cookenboo's study reduces the n-factor case to a three factor case, in pipe diameter, horsepower and miscellaneous components, establishing constant values for the safety factor (a function of pipe yield or bursting strength) and wall thickness (assumed to be minimum consistent with specified safety factor) thereby pre-determining

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[6] J. E. White (1969), "Economies of Scale", p. 151.

[7] Cookenboo (1954), "Costs of Operating Crude Oil Pipelines", pp. 100-112.

operating pressure. This reduces the problem to one of determination of optimum line sizes for various throughput ranges. Thus, with throughput and line size so determined and wall thickness and pressure predetermined, horsepower is determined.[8]

The basis of the preceeding discussion can be clarified somewhat by reference to a mathematical and graphical presentation of production planning.[9] Consider the family of isoquants of the form

$$(1) \quad q^i = f^i (x_1, x_2)$$

where q^i is constant production or throughput in, say, barrels per day at level i; x_1 is horsepower and x_2, inside pipe diameter, both variable factors of production. There are reasonable grounds for suggesting that these factors could be considered as proxies for the conventional labour and capital factors of production theory since the former, horsepower, is analogous with variable inputs such as labour and fuel and the latter, diameter, is associated with capital. (Originally diameter was considered fixed in this analysis and so was perfectly analogous to capital. Now, it is considered variable in a planning context.) Production at the rate of q can be achieved by the application of different amounts of the two variable factors, x_1 and x_2. Figure 4 shows a family of isoquants, the

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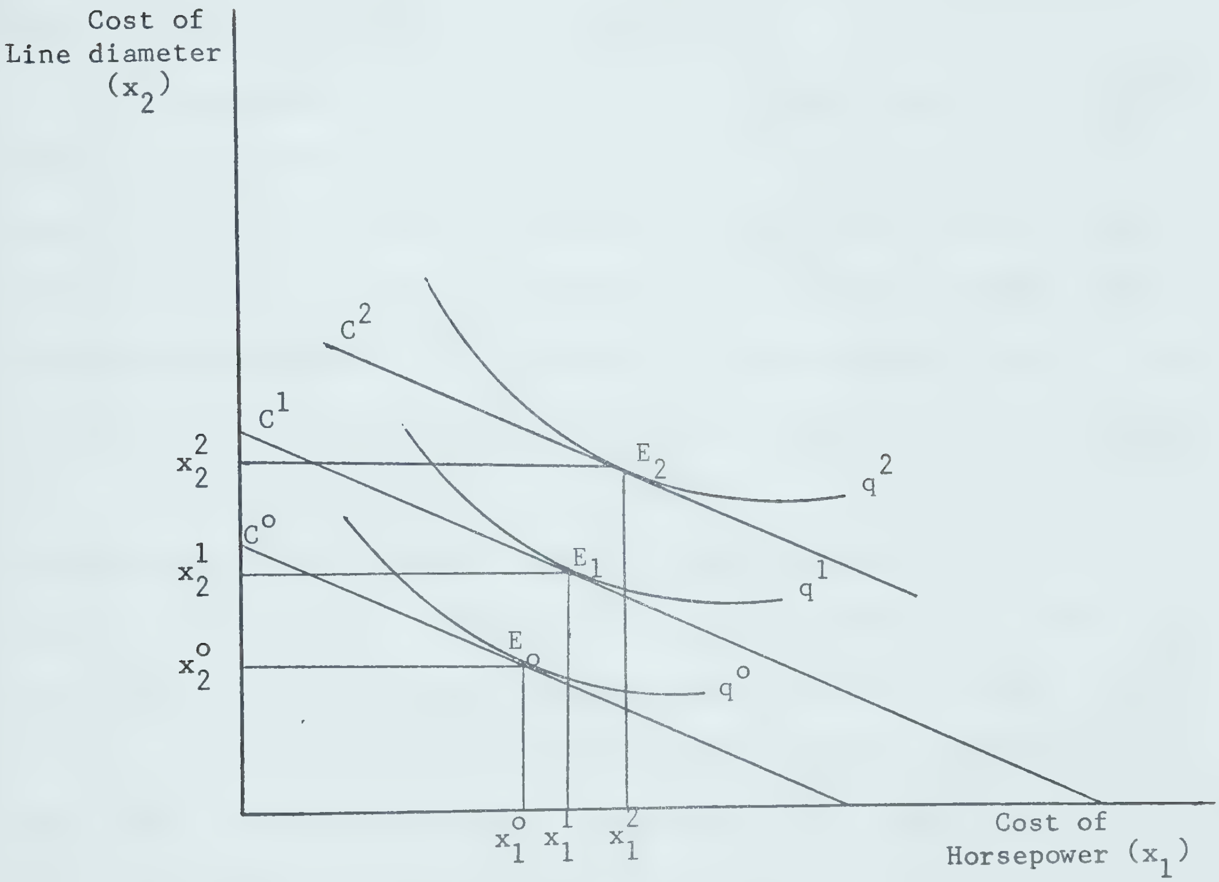
[8] Cookenboo (1954), "Costs...", p. 57.

[9] The mathematical and graphical analysis follows that given in James M. Henderson and Richard E. Quant, Microeconomic Theory -- A Mathematical Approach, (Toronto: McGraw-Hill Book Company, 1958), pp. 44 - 50.

FIGURE 4

PRODUCTION FUNCTION FOR PIPELINES: LINE DIAMETER VERSUS HORSEPOWER (Throughput constant)



Source: based on Leslie Cookenboo Jr. (1955), <u>Crude Oil Pipelines</u>, p. 15. For the sake of simplicity a family of continuous isoquants has been shown above. In reality pipe sizes and power would not be available in perfectly divisable units so the function would be discrete rather than continuous.

loci of which show all possible combinations of x_1 and x_2 which yield the specified outputs q^i. Thus, the total differential of (1)

(2) $dq = f_1\, dx_1 + f_2\, dx_2 = 0$

for movements along the same isoquant where f_1 and f_2 are the first partial derivatives of (1) with respect to x_1 and x_2. These partials are also the marginal productivities of the factors.

The optimization problem becomes one of determining the least costly combination of factor inputs x_1 and x_2 that will yield given levels of output q^i. This requires the introduction of an isocost function of the form given below in equation (3) showing the relationship between specified total variable costs of production, C^i, factor prices r_1 and r_2, and the quantities of these factors x_1 and x_2. The isocost family of functions

(3) $C^i = r_1\, x_1 + r_2\, x_2 + b$

show the loci of input combinations that may be purchased for a specified total cost, C^i. Prices of the factors x_1 and x_2 denoted by r_1 and r_2 respectively, in a pipeline industry context are composite prices. That is, the unit costs of these factors include all initial outlays variant with line diameter and horsepower (eg. line pipe, valves, pumps, etc.) as well as all subsequent line and station operating expenses (eg. power, labour, maintenance, etc.). Diagramatically, the optimum configurations or input combinations for specified levels of output are the tangency points E_i of the isocost lines C^i with the isoquants q^i in Figure 4. In analytical terms, the first order conditions for a constrained cost minimization are derived in the following way. The problem is stated as

(4) Minimize $Z = r_1x_1 + r_2x_2$

(5) Subject to $q^o = f(x_1, x_2)$

where Z = total cost of production

r_1, r_2 = prices of factors x_1 and x_2

q^o = specified output level

Forming the Lagrangian function (6) and differentiating with respect to x_1, x_2 and the Lagrangian multiplier μ, obtains

(6) $L = r_1 x_1 + r_2 x_2 + \mu [q^o - f(x_1, x_2)]$

(7) $\frac{\partial L}{\partial x_1} = r_1 - \mu f_1 = 0$ for minimum

(8) $\frac{\partial L}{\partial x_2} = r_2 - \mu f_2 = 0$ for minimum

(9) $\frac{\partial L}{\partial \mu} = q^o - f(x_1, x_2) = 0$ for minimum

Setting (7), (8) and (9) equal to zero (first order condition for a minimum) and dividing (7) by (8) restates the first order condition for constrained cost minimization and tangency as

(10) $\frac{r_1}{r_2} = \frac{f_1}{f_2} = \text{RTS}$

Thus, for tangency and constrained cost minimization the ratio of the factor prices must equal the rate of technical substitution of the factors RTS or the ratio of the marginal productivities of the factors.

Table 10 presents Cookenboo's 1952 results of the above stated general constrained minimization problem for a typical 1000 mile crude oil pipeline system. The data given is for 1952 and shows optimal line diameters consistent with cost minimization for throughputs ranging from 50,000 barrels per day to 400,000 barrels per day. Minimum costs in each throughput

TABLE 10

ANNUAL COSTS OF CRUDE OIL TRUNK
PIPE LINE OPERATION -- 1000 MILE LINES
(1952)

Throughput (ooo's b/d)	Line Diameter (in.)	Total Annual Costs (ooo's of $)	Costs per barrel per 100 miles (cents)
50,000	8 5/8	9,640.1	5.28
	14	4,131.7*	2.26*
	18	4,595.9	2.51
100,000	10 3/4	18,610.3	5.10
	20	5,900.6*	1.62*
	26	6,486.4	1.78
150,000	18	8,496.8	1.55
	24	6,928.6*	1.26*
	30	7,457.5	1.36
200,000	20	9,947.4	1.36
	26	7,839.6*	1.07*
	32	8,239.0	1.12
300,000	20	18,310.7	1.67
	26	10,460.1	.95
	32	9,361.5*	.85
400,000	30	11,498.4	.77
	32	11,005.8*	.75*

Source: based on Leslie Cookenboo Jr., (1954), "Costs of Operating Crude Oil Pipe Lines", pp. 106, 107.

*optimal

range are denoted by an asterisk. Several simplifying assumptions were used by Cookenboo all of which could be adapted to suit particular situations:

a. reference crude oil is 34° API gravity with a viscosity of 60 SUS (Saybolt Universal seconds);

b. no net gravity flow over the assumed five per cent terrain variation;

c. 25 year project life, four per cent interest rate, and one per cent property tax (federal income tax not included);

d. wall thicknesses all assumed to be one-quarter inch with safety factor of 1.8 (ie. ratio of yield strength to maximum operating pressure).

Unfortunately, these simplifying assumptions do not conform closely to the actual mechanics of pipeline design and planning. Although assumptions (a) and (b) above could easily be changed to suit alternative geographical circumstances and different grades of crude oil, changes in assumptions (c) and (d) considerably complicate the analysis. Project life for tax and payout purposes may differ substantially due to the degree of risk involved. It has been mentioned that the payout period for the proposed Arctic pipelines would suitably reflect the high degree of risk in laying pipe under high cost and environmentally stringent conditions and particularly where reserves of gas and oil sufficient to support a large scale pipeline are as yet unproved. Interest rates, being a proxy for the price of capital, directly affect decisions concerning the trade off between fixed and variable cost proportions in pipeline design. An example will illustrate the complexity of this problem.

Consider the possible trade offs between using thicker wall "tele-

scoped"[10] pipe versus thinner wall pipe throughput. In the former case, savings accrue as a result of fewer pumping stations operating at higher discharge pressures but these savings are offset by higher costs for the steel pipe which is priced in dollars per ton plus freight and higher station operating costs. In the latter case, thinner wall pipe having a lower yield strength (conventional non-alloy steel) requires lower operating pressures and shorter pumping station spacing but these higher costs may be offset by substantial savings in the costs of pipe. With some risk of oversimplification, it can be stated that the main criteria in considering these tradeoffs are the relative prices and costs of fixed capital components (including interest charges on debt and equity allowance for risk and other opportunity costs) and those of the variable factors (labour, fuels, etc.) even though the latter have been shown to comprise a smaller proportion of total costs in the pipeline industry.

Economies of Scale in Pipeline Operation

It will be recalled that the long run average cost function was defined as the envelope curve to the intermediate average cost functions, embracing the minimum cost ranges on these curves for each level of throughput with all inputs including pipe diameter variable. Declining long run average costs are economies of scale in this context and it is to the framework for analysis of these factors that the discussion now turns.

Approaches to Empirical Verification

Two possible approaches to empirical verification of scale economies

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[10]"Telescoping" of line assembly refers to the joining of pipe lengths of different wall thicknesses. Usually thicker wall pipe is used at the discharge end of a pump station due to the higher discharge pressures and consequent requirement for higher yield strength pipe.

prevalent in pipelining are possible. The first is based on accounting data from company sources. Apart from the near impossibility of actually obtaining research access to such data from individual companies, the usefulness of such information is doubtful since invariably it is neither disaggregated from total company operating expenses nor categorized by line diameter or horsepower configuration. Generalizations to other types of pipeline systems and similar systems in different terrains or environments would be hazardous. Cost differences between pipeline systems could also be accounted for by unstable demand patterns in the markets served, different qualities and types of petroleum (and products) transported, and efficiency and age of the plant and equipment.[11] Milton Friedman points out the additional conceptual difficulty that if the firm has made a mistake in planning system capacity which is either smaller or larger than the optimal size, the loss from the mistake will have become capitalized either by accounting practice or ownership changes,[12] thereby concealing the exact nature of costs as theoretically defined by the economics literature.

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[11]An excellent summary of these problems is given in John Haldi and David Whitcomb, "Economies of Scale in Industrial Plants", Journal of Political Economy, Vol. 75, No. 4, (August, 1967) pp. 373-385. See also ____________, "Appendix to Economies of Scale in Industrial Plants", (August, 1967), [mimeographed]; Caleb E. Smith,"Survey of the Empirical Evidence on Economies of Scale", in Business Concentration and Price Policy, A Conference of the Universities-National Bureau Committee for Economic Research, (Princeton: Princeton University Press, 1955), pp. 213-230; Milton Friedman, "Comment", op. cit., pp. 230-238; and J. Johnston, Statistical Cost Analysis, (New York: McGraw-Hill Book Company, 1960) esp. pp. 186-194.

[12]Friedman, "Comment", p. 232.

Haldi and Whitcomb have made a reasonable case for the use of engineering cost estimates in empirical studies of scale economies since the assumptions embodied by the engineering estimates are similar to those underlying the envelope curve.[13] These are the constancy of relative factor prices and supplies, homogeneous product, and similar embodied technologies as between plants. Haldi and Whitcomb further postulate that even though engineering estimates may err substantially, the relative slopes of the cost curves are not likely to be significantly changed. So, while absolute cost levels are susceptible to some inaccuracy, scale economies as reflected by the relative slopes of the cost curves, would be reasonably well estimated by engineering data.

Technological Scale Economies

Following the Haldi-Whitcomb analysis, it is possible to break down pipeline economies of scale into those associated with technological scale economies in the costs of basic industrial equipment, those associated with construction and installation costs, and finally those associated with operating costs. By the former is meant that increases in plant capacity require a something less than proportional increase in materials and labour. In a pipeline context, it has been obvious that such economies obtain as a direct result of the geometric property that pipe capacity increases more than proportionately with diameter. The approximate relation is, in fact,

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[13]Haldi and Whitcomb, "Economies of Scale in Industrial Plants", p. 374.

$$(11) \quad T \propto D^{2.656}$$

where T = throughput

D = inside diameter[14]

Circumference and wall thickness the chief determinants of materials costs and capacity is determined by cross-sectional area, length and strength. Thus, if the cylindrical area, A, of a pipe section of length L, is given by $2\pi r \cdot L$ and the volume of the same section, V, by $\pi r^2 L$, an increase, x, in the pipe radius yields a greater than proportionate increase in the volume of the pipe section compared to the increase in circumference. That is,

$$A = 2\pi^r L$$

$$A' = 2\pi (r + x) L = 2\pi rL + 2\pi xL$$

$$\Delta A = 2\pi x L$$

$$V = \pi r^2 L$$

$$V' = \pi (r + x)^2 L = \pi r^2 L + 2\pi rxL + \pi x^2 L$$

$$\Delta V = 2\pi rxL + \pi x^2 L$$

Since $2\pi x L < 2\pi rxL + \pi x^2 L$

It follows that

$$(12) \quad \Delta A < \Delta V$$ [15]

Economies of Scale Attributable to Construction and Installation

Costs attributable to construction and installation costs, unlike

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[14] White (1970), "Economics of Large Diameter ...", p. 30.

[15] As demonstrated by Cookenboo (1955), Crude Oil Pipelines, p. 20.

those which derive from the technological properties of pipelines as discussed above, may either decline or increase but most certainly are not as amenable to analysis due to the problem of indivisabilities in the sizes and ranges of equipment available in a pipeline system. This problem may be expected to directly affect materials cost and installation cost estimates although the available range of pipe sizes and specifications and pumping equipment is expanding.

It is necessary to establish in this section that costs per barrel of throughput associated with construction and installation and materials costs of larger diameter lines declines. It is reasonable to expect that while installation costs of a 36 inch diameter line as compared to a 32 inch diameter line would be greater in the absolute sense, it is also reasonable to expect that many of the other fixed cost items such as right-of-way acquisition, surveying and line preparation, etc., increase less than proportionately with the costs of diameter increases and thus, averaged over greater throughput, scale economies are attainable.

A priori, it is similarly reasonable to expect that economies of scale are realized on labour, power and utilities costs. In the first instance, it has been pointed out that direct labour includes station operators and maintenance crews; these vary neither with throughput nor pipe diameter but with the number of stations and distance. Since most stations are on semi-automatic operation, operators and other staff perform largely a monitoring, supervisory and dispatching role which can be accomplished by approximately the same numbers of staff for any throughput or any pipe diameter. In respect to power and utilities components of operating costs the potential for scale economies is quite evident. It is a well established

fact that the same amount of horsepower applied to a larger diameter pipeline obtains a greater throughput due to lower friction. This may be extended to infer that with greater pipe diameters and larger required throughputs over time, horsepower requirements and power costs increase something less than proportionately. Also, a possible reinforcement to the existence of positive scale economies in the use of power might be the lower unit power costs for larger block power purchases since most power utilities charge on a declining block rate structure.

Empirical Evidence of Scale Economies

Reference to Table 10 quite clearly shows that total annual costs of pipeline operation per barrel of throughput declines with increasing throughput and with increasing pipe diameter. The components of average total costs of operation are seen to be comprised of horsepower costs, the cost of line diameter (pipe materials) and other miscellaneous annual expenses. Inspection of data in Table 11 verified the following observations about the nature of scale economies vis à vis the above cost component for optimally configured pipeline systems (ie. diameter of line consistent with least annual costs per barrel of throughput):

a. Horsepower costs (initial and recurrent) per barrel of throughput for pipelines of over 1000 miles declined from $0.07 per barrel in 10 3/4 inch diameter line designed to carry 25,000 b/d to $0.021 per barrel in 32 inch diameter line designed to carry 400,000 b/d. (Costs of horsepower expressed in cents per barrel per 100 miles declined from $.007 to $.002).

b. Cost of line diameter (ie. pipe materials costs and installation) per barrel over a distance of 1000 miles declined from about $.24 per barrel ($.024 per barrel per 100 miles) in

a 10 3/4 inch, 25,000 b/d line to \$0.048 per barrel (\$0.005 per barrel per 100 miles) in a 32 inch, 400,000 b/d line.

c. Miscellaneous other costs, while increasing in absolute terms over the throughput ranges, declined substantially when averaged over throughput.

So much for observed scale economies based on Cookenboo's 1952 data. What was intended to be established here was that there is some evidence for concluding pipeline long run costs in fact decline with both increasing diameter and increasing throughput. Although the absolute cost magnitudes of the cost components undoubtedly have changed since the study was done, it is rather unlikely that relative costs have altered such as to reduce potential returns to scale. It is entirely possible that with the installation cf more sophisticated control equipment and a greater degree of automation in some lines, the costs of these fixed components have risen relative to those of power and labour, thereby reinforcing the potential for increasing returns to scale in the larger throughput ranges.

It is useful to mention one other approach to the empirical study of scale economies in pipeline systems. Haldi and Whitcomb, deriving a measure for scale economies in industrial equipment utilization, postulate that returns to scale from technological/geometrical factors, such as the volume-circumference relation analyzed earlier in this section, can be functionally represented by

(13) $C = aX^{b}$

where C = cost

a = constant of regression

X = measure of capacity

b = scale coefficient[16]

A value of $b < 1$ implies increasing returns to scale or decreasing unit costs, $b > 1$ decreasing returns, and $b = 1$ constant returns to scale. Observations on the variables were drawn from engineering cost estimates and the equation estimated by ordinary least squares regression using a logarithmic transformation of (13) above of the form

$$(14) \quad \log C = \log a + \hat{b} \log X$$

Although Haldi and Whitcomb's study sampled only one cross-country pipeline system, their estimate of the scale coefficient, $\hat{b}$, was

$$(15) \quad .60 < \hat{b} < .70$$ [17]

indicating moderate economies of scale in this one system.

Using this particular regression approach to estimate the scale coefficient obtained a similar result when applied to Cookenboo's 1952 data (from Tables 10 and 11). If pipeline capacity X in barrels per day is regressed on total annual costs of operation, C, sampling only the 11 optimal least cost configurations in the Cookenboo data (ie. diameter and throughput configurations yielding the lowest per barrel total annual costs as given in Table 11) and utilizing the logarithmic transformation of the basic exponential form of equation (13), the following estimate of equation (14) resulted

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[16] Haldi and Whitcomb, "Economies of Scale", p. 376.

[17] Haldi and Whitcomb, "Appendix to Economies of Scale in Industrial Plants".

TABLE 11

ANNUAL COSTS OF OPTIMAL CRUDE OIL PIPE LINE CONFIGURATIONS
1952[a]
(1000 MILE LINES)

(Thousands of Dollars)

THROUGHPUT (B/D)	OPTIMAL LINE DIAMETER	(1) HORSEPOWER COSTS	(2) COST OF LINE DIAMETER	LINE DIAMETER AND H.P. (1) & (2)	(3) OTHER COSTS	TOTAL ANNUAL COSTS (1) + (2) + (3)	COST/BBL. PER 100 MI. Cents
25,000	10 3/4 (in.)	708.0	2164.7	2872.7	303.8	3176.5	3.48
50,000	14	967.0	2823.1	3790.1	341.6	4131.7	2.26
75,000	16	1333.0	3324.3	4658.0	379.5	5037.5	1.84
100,000	20	991.0	4492.3	5483.3	417.3	5900.6	1.62
125,000	22	1072.0	4895.2	5968.0	455.2	6423.2	1.41
150,000	24	1148.0	5286.7	6435.6	1193.0	6928.6	1.27
200,000	26	1526.0	5744.7	7290.9	568.7	7839.6	1.07
250,000	30	1375.0	6524.9	7900.5	644.3	9544.8	.94
300.000	32	1592.0	7048.8	8641.5	720.0	9361.5	.85
350,000	32	2267.0	7048.8	9316.0	795.8	10111.8	.79
400,000	32	3085.5	7048.8	10134.3	871.5	11005.8	.75

Source: based on Cookenboo (1954), op. cit., pp. 106, 107.

[a]Assumptions are identical to those given in Table 10. All costs are for a 1000 mile pipeline, 35 °API, 60 SUS crude oil line, uniform terrain conditions, etc.

$$(16)\quad \log C = \underset{(24.881)}{1.49117} + \underset{(39.142)}{.45483} \log X$$

or, having taken antilogarithms

$$(17)\quad C = 30.986\, X^{.45483}$$

It would seem, therefore, that there are reasonable empirical grounds for suggesting the existence of potential scale economies in pipeline operating costs with increases in capacity. Estimates of both the intercept and slope coefficients are significant as shown by the inspection of values of the t statistic in brackets under the coefficient estimates. Several qualifications regarding possible interpretation or application are in order, however. The Cookenboo data, upon which the above simple linear regression was based, was cross-sectional, non-homogeneous industry engineering cost data and as such wide variations in the magnitudes of the cost estimates were possible due to different operating conditions of the lines surveyed. Also, the computed scale regression coefficient was based on 11 observations only of optimally configured systems.

Regressing capacity as measured by throughput barrels per day on annual horsepower costs (which average 25 to 35 per cent of total operating costs, the dependent variable of the first regression above) yielded

$$(18)\quad \log C_{HP} = \underset{(2.4955)}{1.0092} + \underset{(5.25392)}{.41217} \log X$$

and the somewhat surprising result that the estimated scale coefficient, $\hat{b} = .41217$, was smaller than that estimated in the total annual cost regression. This would indicate greater potential scale economies. Recall that the degree of potential scale economies is <u>inversely</u> related to the value of the scale coefficient. That the smaller the scale coefficient, the greater is the potential for scale economies.

Although the coefficients are both significant at the one per cent level in the second regression, the intercept coefficient is not significant at the five per cent level. This fact combined with the unexpected lower estimated scale coefficient[18] indicates most probably that the data is at fault and a larger cross-sectional sampling of engineering cost estimates for optimally configured systems would lead either to the abandonment of the specification of the regression in its present form, thus rejecting the scale relationship between horsepower annual costs and capacity, or a confirmation of the a priori expectation of a scale coefficient higher than that estimated in the first regression. It is certainly expected that with the greater proportion of total annual pipeline costs attributable to the costs of diameter (and other fixed costs), estimates of the scale coefficient would be higher than those for horsepower costs.

Pipeline Transportation Costs

This section is concerned with integrating elements of the derived cost structure in the previous part with a more general transportation economics analysis of petroleum. Specifically, what is intended is to represent the basic structure of pipeline transportation costs of petroleum by tariff rates of the principal pipeline operators.

Basis of Pipeline Tariffs

The basis of tariff structures in Canadian interprovincial petroleum pipelines is the determination of a fair and reasonable rate of return

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[18] One would expect a higher estimate of the scale coefficient ie. $b \gg .50$, reflecting considerably lower potential scale economies.

on the allowable rate base. If a common carrier public utility, the pipeline company's charges are open to some degree of scrutiny by the National Energy Board. In the case of crude oil pipelines, second and third party objections to tariff rates can be heard by the N.E.B. and some intervention in setting the tariff might be expected after a hearing convened to hear these matters. To date, however, the N.E.B. has not directly intervened in the determination of a fair and reasonable rate of return. This rate for crude oil lines has stablized at about 10 per cent on the value of plant and equipment. In the case of natural gas pipelines, the N.E.B. and numerous public utilities boards at the provincial and municipal level have the authority to intervene in the establishment of rates of return since gas lines are more properly public utilities.

Allowable rate bases upon which the rate of return is set differs with the commodity handled (crude oil, natural gas, etc.). Generally speaking, though, the base would be comprised of investment in plant and equipment and some components of operating (or variable costs). The National Energy Board Act which specifies uniform accounting practices for all pipelines within its jurisdiction sets the rate base for gas and oil pipelines but, as has been mentioned, only for gas lines has it actually intervened in the determination of a fair and equitable rate of return. However, shippers of crude oil do have recourse to request a hearing and adjustment to the carriers tariffs if the shipper feels the rates are unreasonable.

The researcher cannot go much beyond the point of examination of determination of the rate of return on the rate base before the realm of accounting practice and interpretation is entered. However, it is possi-

ble to establish a general approach to determination of the cost of service following general industry financial practices which will partially help to resolve the preceeding cost analysis approach to transport costs versus the accounting approach. Amortized total costs of investment for pipelines depends on the debt/equity structures of the new or existing pipeline. In capital intensive, high fixed cost pipeline systems, up to 75 per cent debt financing is common with something in the order of 25 per cent from equity financing. The respective rates of return on these portions naturally varies with the degree of risk, allowance for equity rates being higher than return on debt financing. The other components of amortized annual cost would include an allowance for other interest payments, and allowances for federal income tax and maintenance.

A hypothetical example of the cost of service formula will help clarify this discussion. Assuming a three to one debt/equity ratio (ie. 75 per cent financing), annual cost of service might be determined by summing the following components:

a. Annual debt financing charge at 10 per cent per annum

b. Annual equity financing charge at 15 per cent per annum

c. Yearly annual costs of operation

d. Other interest payments at 10 per cent

e. Federal income taxes at 3 per cent of annual operating costs

f. Maintenance costs per year at 2 per cent of investment in plant and equipment[19]

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[19] Source: Edward A. Jones, Consulting Engineering, Interview, (Calgary: August 2, 1972).

Adding the approved or expected annual rate of return to this base would determine the annual cost of service for pipelines. Actual pipeline tariffs are then set such as to earn the rate of return and cover the expected cost of service so determined.

Structure of Pipeline Tariffs

The nature of costs in the pipeline industry account in large part for the peculiar structure of pipeline tariffs. With large proportions of annual costs attributable to the amortized initial and recurrent expenses of plant and equipment, and smaller proportions attributable to variable or operating expenditures on labour, fuel, etc., it is necessary to structure tariffs so as to attract the greatest distance throughput volumes to cover fixed costs. It is for this reason that transportation tariffs on petroleum are "telescoped". Although the tariff on crude petroleum from Edmonton to Sarnia is higher in absolute terms than the tariff from, say, Regina to Sarnia (ie. \$.47 per barrel Edmonton to Sarnia, \$.39 Regina to Sarnia), the marginal rate is lower over the longer distance (ie. Edmonton to Sarnia - \$.027 per barrel per 100 miles compared to Regina - Sarnia at \$.0288 per barrel per 100 miles). The explanation for the differential or telescoping marginal rate structure lies in the fact that greater volume demands originate in the Province of Alberta than crude sources closer to the eastern refining markets. Also, loading, terminal and storage expenses are higher per barrel on lower volume and shorter distance throughputs than on large long distance batches.

Tariff structures for the two main interprovincial crude oil pipeline systems (Trans Mountain and Interprovincial) are given in Tables 12 to 15.

TABLE 12

TRANS MOUNTAIN OIL PIPE LINE COMPANY
TARIFFS ON PETROLEUM
APRIL 1, 1972

(tariff per barrel)

From	To	API Gravity 30° to 50°	API Gravity 50° to 100°	API Gravity over 100°
Edmonton	Burnaby	$ .400	$ .365	$ .280
Edmonton	Kamloops	.330	.301	.231
Edson	Burnaby	.350	.319	.245
Edson	Kamloops	.280	.256	.196

Source: Trans Mountain Oil Pipe Line Company, Tariff, No. 14, April 1st, 1972, Vancouver, B.C. [published tariff sheet sent to all shippers].

TABLE 13

TRANS MOUNTAIN OIL PIPE LINE
TARIFF STRUCTURE-CRUDE OIL
(April 1, 1972)

Edmonton Station to	Distance (Miles)	Tariff (¢/bbl.)	¢ per hundred bbl. miles
Kamloops, B.C.	511	33	6.5
Burnaby, B.C.	718	40	5.6
Ferndale, Wash.	703	40	5.7
Anacortes, Wash.	728	40	5.5
Edson Station to			
Kamloops	370	28	7.6
Burnaby	577	35	6.1
Ferndale	562	35	6.2
Anacortes	587	35	6.0
Kamloops Station to			
Burnaby	207	17.4	8.4
Ferndale	192	17.4	9.0
Anacortes	217	17.4	8.0

Source: based on information in Trans Mountain Oil Pipe Line Company, "General Article", (Vancouver: April 1971), (mimeographed).

TABLE 14

PUBLISHED TARIFFS, INTERPROVINCIAL PIPE LINE COMPANY, APRIL 1, 1972

FROM \ To	Hardisty Station		Kerrobert Station		Milden, Sask. Takeoff		Regina Station		Gretna Station		Sarnia, Ont.		Oakville	
	CP	RP	CP	RP	CP	RP	CP	PP	CP	PP	CP	PP	CP	PP
Edmonton Station	7.9	----	11.7	----	----	15.5	18.7	20.6	27.8	----	47.0	51.3	50.0	----
Hardisty Station	----	----	----	----	----	----	15.4	----	25.1	----	45.1	49.4	48.1	----
Kerrobert Station	----	----	----	----	----	----	11.8	----	22.1	----	43.2	47.5	46.2	----
Regina Station	----	----	----	----	----	----	----	----	15.6	----	39.0	----	42.0	----
Cromer Station	----	----	----	----	----	----	----	----	10.3	----	35.9	----	38.9	----
Sarnia Station	----	----	----	----	----	----	----	----	----	----	----	----	9.2	----

Source: Interprovincial Pipe Line Company, April 1st, 1972.

Notes: [a]CP refers to tariff in ¢/bbl. light crude petroleum having an A.P.I. Gravity in excess of 30° at 60° F. RP refers to tariff in ¢/bbl. on refined petroleum products (motor gasolines, diesel and heating oil) having an A.P.I. gravity in excess of 30° at 60° F. and a vapour pressure not exceeding 130 psia. PP refers to petroleum products or the indirect liquid petroleum products of oil or gas wells having a vapour pressure in excess of a Reid vapour pressure of 15 pounds at 100 degrees Fahrenheit (ie. natural gas liquids and condensate). The rates quoted for refined product are for up to 100 psia product and these progress in increments of 2.0¢/bbl. and 3.0¢/bbl. for products whose vapour pressures exceed 100 psia by up to 10 psia; 10 to 20 psia; and 20-30 psia respectively.

[b]Blanks mean no present movement of crude petroleum or petroleum products and consequently no established tariff structure is filed with the National Energy Board.

TABLE 15

TARIFF STRUCTURE
IN ¢ PER 100 BARREL MILES
INTERPROVINCIAL PIPE LINE COMPANY

Edmonton to	Distance (miles)	Crude Oil Tariff (¢/100 bbl. miles)	Ref. Products Tariff (¢/100 bbl. miles
Hardisty Station	125	6.32	----
Kerrobert Station	225	5.20	----
Milden, Sask.	300	----	5.17
Regina, Sask.	438	4.27	4.70
Gretna, Man.	772	3.60	----
Sarnia, Ont.	1741	2.70	2.95
Toronto, Ont.	1897	2.63	----
Kerrobert to			
Regina	220	5.36	----
Gretna	547	4.59	----
Sarnia	1516	2.85	----
Toronto	1672	2.76	----
Regina to			
Gretna	334	4.67	----
Sarnia	1303	2.99	----
Toronto	1459	2.88	----
Cromer to			
Gretna	175	5.89	----
Sarnia	1144	3.14	----
Toronto	1300	2.99	----

Source: Computed from Interprovincial's published tariffs and approximate measured distances.

Table 12 presents Trans Mountain's published tariffs on crude oil, stablized and/or debutanized crude oil and condensate, natural gas liquids or indirect unrefined liquid products of oil and gas wells and processing plants, natural gasoline and liquified petroleum gases. The above are in ascending order of API gravity and tariffs listed in the Table are by API gravity groups, the lighter products (ie. greater API gravity) being relatively cheaper to ship than the heavier crudes. The telescoping nature of the structure of Trans Mountain's tariff on crude oil can be seen from Table 13 where marginal rates vary from \$.09 per barrel per hundred miles over shorter distances to \$.055 per barrel per hundred miles over the longer Edmonton-Anacortes haul.

A similar telescoping rate structure exists on the Interprovincial Pipe Line Company system to Sarnia (see Tables 14 and 15) with marginal rates on crude oil varying from \$.063 per barrel per hundred miles to \$.026 per barrel per hundred miles. Direct comparison of the tariffs for refined products in the Interprovincial system and gas liquids in the Trans Mountain system are not possible, however, since Trans Mountain has no established tariff on refined products or the more volatile gas liquids. It is interesting to note, nevertheless, that Interprovincial's tariffs for refined product and processed petroleum products are higher than its tariff on crude petroleum while Trans Mountain's tariff on gas liquids including condensate is <u>lower</u> than its tariff on crude oil. This is due to the fact that Trans Mountain has approval only to carry petroleum products whose blended vapour pressure is not in excess of 15 pounds Reid at 100° Fahrenheit. While products with higher pressures may be accepted, they must be mingled with lower pressure product, condensate or crude such that the

blended batch does not exceed this specification. Generally speaking, though, refined and processed petroleum products (NGL's and LPG's) cost slightly more to transport in a pipeline due to greater safety, control and batching requirements for these more volatile commodities even though the lighter less viscous products are more easily pumped.

Share Estimates of Petroleum Transportation Costs

The share of crude petroleum delivered prices attributable to pipeline transportation costs is easily determined by reference to a current field price series and published tariffs of the gathering and trunk line operators. Results of share computations for selected Alberta crude oils from different fields and with different gravities is presented in Tables 16 and 17. The particular reference crudes selected are from geographically distinct fields each being served by a different gathering system operator.

In Table 16, which shows the share of pipeline transport costs in delivered crude prices at Edmonton and Sarnia, the share is seen to vary at Edmonton depending directly on the distance to the source field and on the posted wellhead price. The most valuable crudes to the producer are, of course, those lighter crudes with low sulphur content located close to trunk line access. Competitive disadvantages would face the producer of the heavier crudes located in the most isolated fields served by a single limited capacity secondary trunk line. Such is the case of producers in the Rainbow field of northwestern Alberta where total transport costs comprise nearly one-third of the Sarnia delivered price making Rainbow crude one of the least competitive light domestic crudes in this market area.

TABLE 16

TRANSPORT COSTS OF SELECTED ALBERTA CRUDE OILS
TO EDMONTON AND SARNIA[a]
1972

	Drumheller (28°-34°)	Kaybob (43°-45°)	Leduc (31°-34°)	Pembina (34°- 39°)	Rainbow (34°-39°)	Swan Hills Main (40°-42°)	Taber North (23°- 24°)	Redwater (35°)
(1) Wellhead Posted Price	$2.52	$2.95	$3.01	$2.84	$2.50	$3.02	$2.00	$2.92
(2) Gathering Charge	--	.175	.04	.09	--	--	.05	--
(3) Pipeline tariff	.17	.025	.07	.05	.55	.055	.45	.05
(4) Edmonton Delivered Price	2.69	3.15	3.12	2.98	3.15	3.075	2.50	2.97
(5) Transport Cost (2) + (3)	.17	.20	.11	.14	.55	.055	.50	.05
(6) % Transport Cost	6.3%	6.3%	3.5%	4.6%	17.4%	1.7%	20.0%	1.6%
(7) Trunk line tariff[c]	$ .47	$ .47	$ .47	$ .47	$ .47	$ .47	$ .54[b]	$ .47
(8) Sarnia delivered price (4) + (7)	3.16	3.62	3.59	3.46	3.62	3.54	3.04	3.41
(9) Transport Cost (5) + (7)	.64	.67	.58	.61	1.02	.525	1.04	.52
(10) % Transport Cost	20.2%	18.5%	16.1%	17.6%	28.1%	14.8%	34.2%	15.1%

[a] The data is drawn from the following sources. Wellhead posted prices are as given in various up-to-date crude oil price bulletins issued by the major oil companies. Pipeline tariffs and gathering charges are from published tariffs issued by the pipeline companies serving the field in question. Where no charge for gathering is listed, it is assumed that the pipeline tariff (item 3) includes gathering charge.

[b] Interprovincial Pipe Line adds 15 per cent to its published tariff for crudes with an API gravity below 25 . Pipeline and gathering tariffs on the Bow River Pipe Line to Edmonton are assumed to include a similar penalty due to low gravity of the Taber crude.

[c] Interprovincial Pipe Line tariff.

TABLE 17

TRANSPORT COSTS OF SELECTED ALBERTA CRUDE OILS TO VANCOUVER/ANACORTES, 1972[a]

	Edson (41° - 42°)	Kaybob (43°-45°)	Pembina (34° - 39°)	Redwater (35°)
(1) Wellhead Posted Price	\$2.94	\$2.95	\$2.84	\$2.92
(2) Gathering charge	.06	.025	.09	--
(3) Pipeline tariff	--	.225	.05	.05
(4) Edmonton Delivered Price[b]	--	--	2.98	2.97
(5) Trunk line tariff[c]	.35	.35	.35	.35
(6) Vancouver/Anacortes delivered price	3.35	3.55	3.33	3.32
(7) Transport Cost	.41	.60	.49	.40
(8) % Transport Cost	12.2%	16.9%	14.7%	12.0%

Notes: [a]For sources see note a to Table 16.

[b]Blanks mean Edmonton delivered price is not relevant since the product does not have to be transported to Edmonton before delivery to the trunk carrier.

[c]Tariffs on Trans Mountain Oil Pipe Line. Heavier crudes below 30° API are subject to no more than 10 per cent penalty (on established tariff) while petroleums with API gravities above 50° and less than 100° realize 8.8 per cent (3.1 cent/bbl.) reductions. Liquids with API gravities above 100° realize 30 per cent (10.5 cent/bbl.) reductions on Edson to Vancouver tariffs.

Understandably, transport costs to Vancouver and Anacortes of selected Alberta crudes comprise a smaller average share of delivered prices in these markets (see Table 17) due to the higher gravity of the crudes selected and relatively inexpensive access to the Trans Mountain trunk line to these market areas. Even though the marginal tariff rates (cost per barrel per 100 miles) are significantly higher over this system, the respective shares are seen to be lower on average than those crudes delivered to Sarnia due primarily to the shorter distance.

Although specific data on refined and processed petroleum products prices of various markets was not available at the time of writing, common sense would lead one to suspect that the share proportions of transport on these higher valued commodities are considerably less. The data in Table 14 indicates that the tariff on gas liquids to Sarnia, for example, amounts to only \$.513 per barrel or \$.043 per barrel more than the crude oil tariff. The tariff on refined motor gasoline to Saskatoon is 15.5 cents plus the internal Gulf Oil tariff from the Milden takeoff point to Saskatoon. This is equivalent to a marginal rate of 5.16 cents per barrel per 100 miles. If the pump price of number one motor gasoline in Saskatoon is taken as \$.52 per gallon, for example, the computed share of transport costs (excluding Milden-Saskatoon pipeline charge) in the pump price is 1.21 per cent or substantially less than the equivalent transport share of delivered crude prices at Saskatoon if crude were delivered to this point.

Locational Factors

This final part of the chapter is concerned with identifying key ele-

ments of a locational analysis of petroleum processing and refining activity with specific reference to implications for development of pipeline systems serving regional and national markets.

Location of Refineries

Large scale complex refining activity in Canada is concentrated close to market and distribution centres in Vancouver, Edmonton, Sarnia and Montreal. Small scale, simpler operations are being carried out in a number of other locations where either the market served is some distance from the major refining centres (eg. Winnipeg and Regina), the local market is on a crude supply line or near a crude oil field, or the local demand is sufficient to justify refining of a specific, but limited, product range.

In more general terms, locational forces bearing on refining activity may be categorized as those economic incentives favouring resource or crude supply orientation and those favoring market orientation.[20] Briefly, some of the factors affecting resources oriented refining activity are:

a. Saving of transport costs for refinery fuel and refining losses;

b. possibility of serving a number of different markets from one refining centre;

c. Regional market size and homogeneity of product mix enabling attainment of scale economic factors in refining;

d. the transport cost of refining product compared to crude transport.

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[20]These factors are based on discussions in S. Morris Livingston, "Economics of Refinery Location in the United States", in Fifth World Petroleum Congress, Proceedings, Statistics and Education, Operations Research, Section IX, (New York: Fifth World Petroleum Congress, June, 1959), pp. 75-84; and P. H. Frankel and W. L. Newton, "Current Economic Trends in Location and Size of Refineries in Europe", op. cit., pp. 85-95.

Factors bearing on refinery location close to major market centres are:

e. cheaper transport of crude oil by pipeline;

f. composition of product demand in the larger markets (eg. a greatly diversified demand for, say, gasoline, fuel oils, petrochemical feedstocks tends to favour the movements of crudes to market oriented refineries);

g. potential plant scale economies including real scale effects (eg. more efficient utilization of plant labour and equipment) and monetary scale effects (eg. savings from larger block purchases of feedstocks, plant fuel or power, etc.); and

h. integrability of product production, distribution and marketing activities.

For any one specific refinery location or expansion decision, many of the above factors become pertinent as do others such as the status of plant technology, long run sources of crude supply and a host of political factors. What is of specific interest in western Canada, though, is the degree to which transportation costs and technology, emergent regional demand patterns for products and the status of Prairie refining technology have become important factors in the consolidation and relocation of refining in the Edmonton area. It is beyond the scope of this study to examine these factors affecting refining location and consolidation in any great detail except to identify those bearing on the development of crude and products pipeline transportation systems eminating from the western Canadian crude source and refining areas. This is one of the primary purposes of Chapter 4 following, but for the present it is sufficient to mention specific analytic approaches.

In respect to the determination of potential scale economies in plant and equipment operation, the approach taken by the Haldi-Whitcomb analysis[21]

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[21] Haldi and Whitcomb, "Economies of Scale in Industrial Plants".

of industrial plants would seem to be directly relevant however many qualifications again have to be made. Their analysis includes estimates of scale coefficients for various process units in petroleum refining; the estimates are given below for some of the more common unit processes[22];

TABLE 18

ESTIMATES OF SCALE COEFFICIENT IN UNIT REFINING PROCESSES

Process	Estimate of b
Catalytic Cracking	.80
Catalytic Polymerization	.70
Thermal Cracking	.51
Vacuum Distillation	.80
Coking	.72

The estimates indicate modest to moderate potential scale economies in the surveyed industries for the unit processes identified. Application of these results to process units in different geographical or market situations may not be valid, however, since it is likely the Haldi-Whitcomb sample was a fairly homogeneous sample of refining operations. Nonetheless, the application of their statistical procedure to say, refining activity in Montreal, Sarnia or Edmonton would likely net reasonable results due to the homogeneity of product demand composition as between refineries in each of the centres.

[22] Haldi and Whitcomb, "Appendix to Economies of Scale in Industrial Plants", p. 9.

It is important to further qualify inferences about the relationship between scale economic factors and locational analysis of refining by mentioning that the central concern in the determination of economies is the processing capacity of the unit (rather than the entire plant) compared with initial and recurrent costs of operation of the unit including materials, labour, power, etc. In specific refining situations, for example Alberta, the potential scale factors are likely to be somewhat larger than in say eastern Canada, due primarily to the relatively narrower range of product demand and consequent limited number of process units required to produce the product mix. The composition of demand for product at Sarnia and Montreal on the other hand, is such as to require a greater range of unit process operations and probably more complex plant infrastructure.[23]

Location of Processing Plants

Gas processing plants which extract sweet, dry, marketable methane gas, gas liquids, residue gas and other by-products are located at the major source gas fields. The reason is simple: it is impractical and inefficient to transport "wet", sour gas in a pipeline except in a secondary or gathering system to a large processing unit.

The location of fractionation plants, however, is a more complex problem. It will be recalled that fractionation plants separate a natural gas liquids (NGL's) stream into its constituent parts, liquified petroleum gases (LPG's), the most common being ethane, propane, iso-butane and normal

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[23] For a more detailed appreciation of the potential for scale economies in simple and complex refining operations see Robert Lindsay, "Regional Advantage in Oil Refining", Papers and Proceedings, Regional Science Association, Vol. 2 (1956) pp. 304-317.

butane, and pentanes 'plus' or condensates. Propane is used chiefly as a domestic and industrial fuel, while the others including the lighter LPG's are used chiefly as refinery and petrochemical feedstocks and refinery product additives. Fractionation represents a further stage in the processing of a gas liquids stream into LPG's and location of the plant is almost entirely oriented to the market for the respective liquified gases. There does not appear to be the kinds of locational comparisons possible as with refining operations vis à vis raw materials supply, or market orientation. Nonetheless,it is observed that the installation of a new large scale fractionation plant at Fort Saskatchewan, drawing gas liquids chiefly from the Kaybob field, resulted from emergent larger scale refinery demands in the Edmonton area for LPG's, specifically butanes, as additives in highly specialized refining processes producing motor gasolines and diesel fuels.

Summary of Chapter

The chapter's focus has been on presenting basic theoretical and analytical concepts pertinent to an analysis of larger scale crude pipeline development and of the emergence of processed and refined product pipeline development in Western Canada. Firstly, by a detailed examination of the cost structure of the pipeline industry, fundamental relationships between the various cost components and their relationship to parameters such as wall thickness, suction and discharge pressure, pipe diameter, etc., was examined. A useful theoretical construct for the optimization of pipeline system operation was shown to be that of the conventional constrained cost minimization problem applying the calculus to derive first order conditions

and optimal values of the variables. The basis of declining long run average costs or economies of scale in pipeline operation was demonstrated to result primarily from the technological properties of a pipeline and the high proportion of fixed to variable cost.

Secondly, pipeline transportation costs were shown to be based on the structure of the transportation tariff for various petroleums. The most important property of the structure of tariffs is the telescoping of marginal rates, ie. higher marginal rates for shorter hauls, and this property was shown to be derived from the necessity to fully utilize a line's throughput capacity in order to realize potential scale economies of operating a particular configuration. Finally, the determination of pipeline transport cost shares in delivered Canadian crude and products prices, once given the basis of pipeline tariffs, was presented. These shares average about 16 to 20 per cent for crude oil delivered at Toronto and Vancouver; the shares for petroleum products are substantially lower.

Locational factors in petroleum refining and processing were introduced in the last part of the chapter. The reason for examination of these factors is the phenomenon of emerging refining consolidation in the Edmonton area, with smaller scale refining operations in other prairie cities being gradually phased out or cut back.[24] This development is directly dependent on the development of efficient, low-cost product pipeline dis-

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[24]Imperial Oil is presently operating refineries at Calgary, Regina and Winnipeg. With the completion of the Company's 140,000 barrel per day Strathcona Refinery in Edmonton in 1974 these smaller prairie operations are expected to be phased out and the centres served by either a new product pipeline from Edmonton or the existing Interprovincial Pipe Line Company "white" line. Gulf Oil Canada has already phased out its Saskatoon and Moose Jaw refineries while its Calgary operation is producing only asphalt.

tribution systems. Gas processing was shown to be resource oriented, although separation of the gas liquids streams was market oriented. The locational orientation of gas processing and particularly the further stage of fractionation is similarly dependent on the availability of pipelines capable of handling the more volatile LPG shipments to refineries and petrochemicals plants.

In Chapter 4 following, elements of the analytic framework derived in the preceeding pages are applied specifically to the development of crude oil and petroleum products pipeline transportation systems in Western Canada. The relationships between refinery consolidation, processing activity and the evolution of these transport systems is examined.

CHAPTER FOUR

APPLICATION OF ANALYTIC FRAMEWORK

This chapter applies the foregoing transport cost and locational analytic framework to the recently observed phenomenon of refinery consolidation in the Edmonton area. Firstly, the phenomenon is identified and the reasons for consolidation of refining activity in Edmonton as cited by one of the major integrated oil companies is presented. These are shown to constitute a set of sufficient conditions for consolidation. Secondly, the development of an efficient products distribution system (products pipeline network) is postulated as being the necessary condition for consolidation. A brief discussion of location of gas liquids fractionation plants and the development of NGL/LPG pipelines is also given.

Consolidation of Refining Activity

Descriptive Background

Reference in previous chapters was made to the new Gulf Oil Canada refinery in Edmonton. This is to serve regional markets in Saskatchewan, Alberta and southeastern British Columbia. Gulf refineries at Saskatoon, Moose Jaw and Calgary have been closed except for asphalt production at Calgary and Moose Jaw and use of terminal storage facilities at Saskatoon. Similarly, it is likely that with the completion in 1974 of Imperial Oil's new 140,000 barrel per day Strathcona refinery in Edmonton further consolidation of that company's refining activities in Edmonton is to be expected although it is uncertain at the present time which prairie refineries would

be closed.[1] The other major integrated companies have not announced either plant expansions or consolidations to date although it is interesting to note that four major companies (Gulf, Imperial, Shell and Texaco) have ownership interest in the Alberta Products Pipeline, the first exclusive refined products line in Western Canada, between Edmonton and Calgary thereby ensuring their respective shares in the southern Alberta - southeastern B.C. product markets should their Calgary operations be closed.

Table 19 lists western Canada's 1971 refining capacity, unit plant processes and capacity, and also the respective product ranges. The disposition of product mix over the same market region is given in Table 20. These data will later be used to illustrate the homogeneity of product mix in the Western prairie provinces,the types of production processes available and the vintage of capital stock.

Precedents for the consolidation and geographical concentration of refining activity at or near the crude supply points or alternatively at major markets or distribution centres are observed in several areas of the world. Britain has a fairly well established concentration of refining activity on her major watercourses or at coastal locations, with products pipelines and other distribution networks eminating from the refining centres inland to other markets.[2] The refining industry in Britain is fortui-

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[1]Imperial Oil operates refineries at Winnipeg, Regina, Edmonton and Calgary. All except Winnipeg are older, small-scale plants as can be seen from Table 19.

[2]The British and European refining and products distribution systems are summarized in Gerald Manners, The Geography of Energy, (London: Hutchinson University Library, 1964), pp. 69-81; and M.E. Hubbard, "Pipelines in Relation to Other Forms of Transport", in World Petroleum Conference, Vol. VI, (Madrid, Spain: World Petroleum Conference, 1960), pp. 3245-3263.

TABLE 19

WESTERN CANADA REFINING
CAPACITY, 1971

Company (startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Manitoba			
Imperial Oil Enterprises, Winnipeg (1951)	21,000	Catalytic Fluid (7100) Vacuum Distillation (8600) Catalytic Reforming (2800) Catalytic Hydro treating -distillate (7500) Polymerization, Catalytic (1100) Asphalt (2000)	motor gasolines aviation gas and tractor fuel turbine fuel kerosene stove, diesel, light fuel oils heavy fuel sulphur
Shell Canada Ltd. St. Boniface (1927)	26,500	Catalytic Fluid (7000) Hydro Cracking(1400) Vacuum Distillation (5500) Catalytic Reforming Platforming (8200) Cat. Hydro Treating -naptha (2500) Polym. Cat. (450) Asph. (200 b/sd)	motor and aviation gas tractor fuel turb. fuel kerosene stove, diesel, light and heavy fuel oils asphalt LPG

Continued

TABLE 19

(Continued)

Company (Startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Saskatchewan			
Consumers Co-op, Regina (1935)	21,500	Thermal delayed coking (3000) Cat. Fluid (9000) Vac. Dist. (8500) Cat. Ref. Plat. (3000) Cat. Hydro Treating -naptha (3000) -dist. (6000) Polym. Cat. (1100) Coke (165 tons)	naptha specialties kerosene motor, tractor gas stove diesels and light and heavy fuel oils LPG coke
Husky Oil, Moose Jaw (1949)	3,500	Vac. Dist. (1900) Asphalt (1000)	heavy fuel oil specialty asphalts
Imperial Oil Enterprises, Regina (1916)	32,200	Cat. Flu. (11,000) Vac. Dist. (14,200) Cat. Ref. (3400) Poly. Cat. (1000) Asphalt (2600)	motor and tractor gas av. turbine fuel kerosene stove, diesel and light fuel oils heavy oil asphalt

Continued

TABLE 19

(Continued)

Company (startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Alberta			
Gulf Oil Canada, Edmonton[a] (1971)	80,000	Atmospheric Dist. (80,000)	Fuel gas
		Hydrodesulphurization (45,000)	sulphur
		Vac. Dist. (23,000)	LPG
		Coker (7200)	Jet B
		Light Refomer (10,000)	Jet A
		Heavy Reformer (5,800)	Diesel fuel
		Hydro Treating) (30,000)	Stove Oil
		Cat Cracker)	Motor gasolines
		Sulphur (40 T/D)	Butane
		Alkylation (10,000)	Isobutane
		Isomerization (3000)	Decant
		Deisobutanizer (3000)	Coke
Gulf Oil Canada, Calgary[b] (1939)		asphalt unit (approx. 1600)	asphalt
Husky Oil Ltd., Lloydminster (1947)	6,500	Vac. Dist. (3400)	asphalts
		Cat. Ref. (940)	turbine fuel
		Cat. Hydro Treating (940)	stove, diesel light fuel oils
		Asphalt (2400)	heavy fuel oil
			motor gasoline

Continued

TABLE 19

(Continued)

Company (startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Imperial Oil Enterprises, Edmonton (1948)	39,900	Cat. Fluid (10,200) Vac. Dist. (15,600) Cat. Ref. (2600) Cat. Hydro Treating (2500) Alkylation (2400) Lube Oils (2500) Asphalt (3400)	motor and av. gas tractor fuel turbine fuel kerosene stove, diesel and light fuel oils heavy fuel oil lube oil asphalt
Imperial Oil Enterprises, Calgary (1923)	19,000	Cat. Fluid (7000) Vac. Dist. (7400) Cat. Ref. (2500) Cat. Hydro treating (5600) Alkylation, H_2SO_4 (1700) Asphalt (1000)	naptha specialties av. gas motor gas tractor fuel av. turbine fuel kerosene stove, diesel and light fuel oil heavy fuel oil asphalt
Shell Canada Ltd., Bowden (1960)	5,000	Cat. Ref. (2200) Cat. Hydro Treating (2000)	motor gas tractor fuel diesel fuel light fuel oil

Continued

TABLE 19

(Continued)

Company (startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Texaco Canada Ltd., Edmonton (1951)	20,000	Thermal Delayed Coking (2000) Cat. Fluid (6500) Vac. Dist. (7200) Cat. Ref. (3000) Cat. Hydro Treating (5700) Coke (as T/D) Poly. Cat. (250)	naptha specialties motor gas av. turbine fuel kerosene stove diesel and light fuel oil heavy fuel oil petrochem. feed
British Columbia			
Gulf Oil Canada, Port Moody (1958, 1970)	30,000	Cat. Fluid (8480) Vac. Dist. (11,800) Cat. Ref. (7900) Cat. Hydro Treating -naptha (10,000) -distillate (10,250) Alkylation (1000) Asphalt	naptha specialties motor gas av. turbine fuel stove, diesel and light fuel oil heavy fuel oil
Gulf Oil Canada, Kamloops	5,900	Cat. Fluid (1900) Vac. Dist. (2000) (Cat. Ref. (900) Cat. Hydrotreating -naptha (1350) -distillate (2000) Poly. Cat. (100) Asphalt (450)	same as above and petrochem. feed

Continued

TABLE 19

(Continued)

Company (startup)	Crude Capacity (b/d)	Plant Units (Capacity b/d)	Products
Pacific Petroleums, Taylor	10,400	Cat. Fluid (3800) Vac. Dist. (1100) Cat. Hydro treating -naptha (4400) -distillate (6500) Alkylation (1100) Asphalt (215)	motor, av. gas tractor fuel kerosene stove and diesel fuel asphalt
Shell Canada, Burnaby (1932)	20,500	Cat. Fluid (6000) Vac. Dist. (7000) Cat. Ref. (2700) Cat. Hydro Treating -naptha (6100) -distillate (10,000) Poly. Cat. (480) Asphalt (2500 b/sd)	naptha specialties av. and motor gas tractor and motor gas tractor fuel av. turbine fuel kerosene stove, diesel and light fuel oil asphalt LPG
Chevron Canada, Burnaby (1936)	18,000	Cat. Fluid (4500) Vac. Dist. (8000) Cat. Ref. (2430) Poly. Cat. (400) Asphalt (2000)	naptha specialties av. and motor gas av. turbine fuel stove, diesel, light fuel oil asphalt LPG
Union Oil Co., Prince George (1967)	8,000	Cat. Ref. (1100) Cat. Hydro Treating Dist. (5200) Asphalt (1000)	motor gas stove, diesel, light and heavy fuel oil asphalt road oil

Continued

NOTES TABLE 19

Source: Most of the data is taken from Canada, Mineral Resources Branch, Department of Energy, Mines and Resources, Petroleum Refineries in Canada, January, 1971, (Ottawa: Information Canada, 1971) Cat. No. M36-71/5, pp. 16-20.

[a] Source: "Gulf's Edmonton Refinery", (Oil and Gas Journal, (June 26, 1972), p. 74; and Mr. G. C. Docken, Edmonton Refinery Manager, Gulf Oil Canada, Interviews (various dates).

[b] Gulf Oil Canada's Calgary refinery is producing only asphalts following the opening of its Edmonton refinery.

TABLE 20

DISPOSITION OF PETROLEUM PRODUCTS FROM
WESTERN CANADIAN REFINERIES, 1969
(barrels)

	Manitoba	Saskatchewan	Alberta	B. C.	Totals
1. Propane and mixes	107,263	184,726		282,336	574,225
2. Butane and mixes	155,445	90,279	134,404	406,207	786,335
3. Petrochemical Feed	8,710			261,784	270,494
4. Naptha Specialties	4,949	6,271	38,614	94,818	145,652
5. Aviation Gasoline	289,264		352,434	177,052	818,740
6. Motor Gasoline	6,657,503	11,225,132	18,763,069	15,296,671	51,943,375
7. Aviation turbo fuel	1,078,908	399,730	1,682,240	1,483,869	4,644,747
8. Kerosene, stove and tractor fuel	541,497	1,532,939	533,425	2,157,870	4,765,731
9. Diesel fuel oil	2,273,353	3,960,042	8,042,841	9,757,366	24,033,602
10. Light Fuel oil	1,470,508	1,897,666	2,817,460	1,673,757	7,859,391
11. Heavy fuel oil	1,387,555	1,750,488	2,037,637	4,530,704	9,706,384
12. Asphalt	421,211	1,093,668	1,950,831	1,199,618	4,665,328

Continued

TABLE 20

(Continued)

	Manitoba	Saskatchewan	Alberta	B. C.	Totals
13. Coke			472,524		472,524
14. Lube oils		20,217	631,601	4,504	656,322
15. Still gas	618,073	952,570	1,746,626	1,871,951	5,189,220
16. Losses and other	-229,018	229,135	1,428,507	- 45,794	1,382,830
Totals all products	14,856,221	23,554,630	40,420,446	39,152,713	117,984,010

Source: Canada, Dominion Bureau of Statistics, Refined Petroleum Products, 1969, Catalogue, No. 45-204, Vol. I, (Ottawa: Information Canada, 1971), pp. 8 - 23.

tously located coincident with large centres of consumption and tanker supply points where crude can be pumped directly to refinery receiving tanks. In Europe, as Manners[3] points out, large geographically concentrated markets are inland of the tanker terminals and crude pipelines connecting the coastal terminals to refinery gates have developed. In both these cases, though, the trend has not specifically been one of actually phasing out refineries which were not optimally located but rather new plants and plant expansions to meet accelerating fossil fuel energy demands have been constructed at the market rather than at the coastal supply points. American experience[4] is perhaps most indicative of the pattern likely to be observed in Canada. There was an absolute decrease in the number of refineries in the United States from 1945 to 1965 while average plant capacity has doubled and geographical concentration of refining activity in key marketing and/or distribution areas has increased.[5]

Within western Canada, the tendency towards consolidation has hardly been noticeable to date, except for the previously cited Gulf Oil example. Refining activity concentrations in Eastern Canada are located at Sarnia and Montreal with their respective products distribution networks extending

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[3]Manners, The Geography of Energy, p. 75-76.

[4]See United States, National Petroleum Council, Impact of New Technology on the U.S. Petroleum Industry 1946-1965. (Washington: National Petroleum Council, 1967) esp. p. 257 ff.

[5]Ibid, p. 301.

throughout the industrialized, populous areas of Ontario and Quebec. Only limited concentration appears to have occurred in the western prairie provinces and British Columbia even though this region would seem to have some of the prerequisite conditions for consolidation and distribution of product by pipeline. It is necessary to emphasize that in the Canadian context the petroleum industry is relatively young and refining has located primarily in response to relative increases in local and regional markets. By world standards, the scale of plant operations of the Canadian refining and processing industry is relatively small but highly dynamic in terms of the nature and directions of its growth.

Reasons for Consolidation

In chapter three, general locational factors bearing on refining were introduced. This section presents an explicit examination of the reasons for the consolidation of one company's refined petroleum products production in Edmonton.

Before proceeding with this, however, it is useful to revert briefly to a Weberian generalization concerning the location of manufacturing. The generalization is that industries tend to locate in areas such that the sum of their production costs including transport costs of raw materials supply and product to market transport costs are minimized, *cetaris paribus*.[6]

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[6] Comparative cost approaches to the study of industrial location are described in some detail in Walter Isard, Location and Space Economy, (Cambridge, Mass.: The M.I.T. Press, 1956), esp. pp. 91 - 119; ______________, *Methods of Regional Analysis: An Introduction to Regional Science*, (Cambridge, Mass: The M.I.T. Press, 1960), esp. pp. 232-308; and Gerald J. Karaska, "The Partial Equilibrium Approach to Location Theory" in Karaska and David F. Bramhall, (eds.), *Locational Analysis for Manufacturing*, (Cambridge, Mass: The M.I.T. Press, 1969), pp. 22-41.

Without disclaiming the relative importance of labour costs, fuel costs, etc., the greater the weight loss of the raw material attributable to further processing or manufacturing to a finished state, and assuming transport costs are based solely on weight or volume and distance, the more likely is the processing or manufacturing activity to locate closer to the source raw materials. However, in modern petroleum refining, product recovery on a barrel of crude oil can be as high as 95 per cent with in-plant fuel use comprising a very small percentage of the crude charge (about five percent of crude charge at Gulf's Edmonton refinery[7]). Thus, in modern refining technology there is very little volume loss and, depending on the geographical pattern of demand for the heavier ends, little weight loss. When considering product distribution to a region by pipeline, though, there are definite restrictions on the range of products that pipeline carriers will transport which prevents complete location near the source. Heavy ends such as asphalt, the heavier fuel oils and cokes, etc. are not pipelined and the status of a particular carrier's control technology and safety factors may well limit the transport of the more volatile products such as LPG or motor gasolines. With advances in pipeline control technology some of these lighter products are now being batched in multi-product lines.[8]

The above digression serves to point out that the volume or weight

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[7] "Gulf's Edmonton refinery: Model of gasoline-making efficiency", <u>The Oil and Gas Journal</u>, (June 26, 1972), p. 73.

[8] Interprovincial Pipe Line Company transports motor gasolines, gas liquids, diesel and stove fuels in the same line as synthetic crude. By a recent Board of Director's decision, the company will also carry LPG's.

loss criterion for orientation of refining activity to raw materials sources, while remaining highly important, does not fully explain this industry's location in western Canada. The analysis now turns to possible reasons why Gulf Oil Canada chose to consolidate its prairie refining operations in Edmonton.

Gulf Oil's Consolidation

Factors confirmed[9] to be relevant to the location of Gulf Oil Canada's new Edmonton refinery and the closure of its other refineries at Edmonton, Calgary, Saskatoon and Moose Jaw include the following:

a. attainable economies of scale with larger plant;

b. availability of raw materials supply including crudes, condensates (high gasoline yield), and field butanes;

c. status of existing plant technology (or vintage of capital) in the other locations and the need to up date plant processes to meet emerging product demands (no-lead and low-lead gasolines);

d. related to the last point on the vintage of capital equipment in the prairie plants is the fact that investment costs of these plants have been written off;

e. environmental factors including product quality requirements and more efficient in-plant use of environmental resources; and

f. availability of an efficient and competitive products transportation system to serve markets once served by local refineries.

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[9]Interviews with Gulf's Edmonton Refinery Manager, Mr. G. C. Docken on several occasions during the course of the study as well as reference to published sources such as "Gulf's Edmonton refinery - model of gasoline-making efficiency" in The Oil and Gas Journal, (June 26, 1972), pp. 72-76, are the bases for the locational factors cited here.

Leaving the last factor to separate discussion in the second part of this chapter, the other factors are most certainly interdependent and the analysis now turns to consideration of each.

The first factor, attainable scale economies, can be considered as being a highly important sufficient condition for consolidation. This follows principally from the notion that if real and monetary economies[10] of operating the new larger scale plant in Edmonton exceed older plant shut-down costs and/or operating costs, and additional distribution costs for refined products, the consolidation is likely to occur. Actual estimates of net real and monetary economies from operation of the new refinery was not obtained in the course of this study, however, due to limitations of time and the absence of a meaningful period of operation of the new plant for which data could have been extracted. The Edmonton plant has been in operation just over one year. Although capacities and throughputs of the various pieces of process equipment are greater than similar equipment at the other Gulf prairie refineries, the new plant embodies much more recent in-plant technology including "unitizing" several of the processes and greater reforming and isomerization capacity, etc. in order to improve the lighter end yield in the product mix.[11] These factors would inhibit derivation of estimates of cost savings based on scale comparisons between the smaller

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[10]Real economies of scale are those cost savings which accrue as a result of more efficient and perhaps, more intensive, processing unit operations in a refinery. Monetary economies of scale are those which accrue from bulk purchase discounts on raw materials including plant fuel, power, etc.

[11]Excellent expositions of the status of refining technology are given in W. Skinner and D.C.D. Rogers, Manufacturing Policy in the Oil Industry, Third Edition, (Homewood, Ill: Richard D. Irwin, Inc. 1970), esp. pp. 47-93; and National Petroleum Council, Impact of New Technology, pp. 281-302.

prairie plants and the new Edmonton plant. Discussions with representatives of the industry during the course of this study, and reference to the various trade journals, have confirmed that direct plant operating costs are substantially lower in the larger scale operations. This point also follows directly from the geometrical demonstration of scale effects in various manufacturing and pipeline industries discussed in chapter three.

Secondly, the proximity of raw materials including crudes, condensate and field butanes would seem to be an increasingly important reason for location in Edmonton. This area is a highly favorable location for refiners concerned with long term supply of feedstocks. It is connected by pipeline to gas liquids and LPG production points, in Alberta as well as by pipeline to extensive reserves and a synthetic crude processing plant at the Athabasca Tar Sands. Also, Northern Alberta is likely to be a favorable location in respect to the development, eventual production and transportation of Mackenzie Delta oil and gas. These frontier basins should extend supply time horizons well beyond forecast relative declines in Alberta crude oil production.

Item c and d above relating to the vintage of existing plant capital equipment and the economic life of the capital are interrelated and deserve further elaboration. Firstly, as indicated by startup dates of the three closed Gulf refineries (1933 for Saskatoon, 1934 for Moose Jaw and 1939 for Calgary), investment costs for these plants have long since been recovered and very little would be sacrificed by closure if the markets originally served by these plants could be served competitively by the larger less costly Edmonton plant. Secondly, and perhaps most important is the

fact that in order for the older Gulf plants to meet modern requirements for the low-lead and non-leaded gasolines, expensive in-process technological changes would be required possibly leading to the entire replacement of existing capital equipment. At Gulf's new Edmonton refinery, field butanes from Alberta source fields are blended into the reformed product stream of motor gasoline base stocks after the former have passed through the isomerization-alkylation unit. The use of butanes in motor gasoline stocks is an effective substitute for tetraethyl lead in improving the octane rating of motor gasolines.[12] Other prairie refining points are considerable distance from sources of butane although pipeline transmission of NGL mix is now possible via Interprovincial Pipe Line at tariffs only slightly higher than crude tariffs.

Finally, there are several environmental factors that can be cited as reasons for the consolidation of refining activity. These factors may be generally grouped into those concerned with the in-plant use of environmental resources (specifically air and water) and those concerned with the consumptive uses of refinery products. Again, these environmental factors are strongly interrelated with other factors discussed above, particularly the status of plant technology. The first group of environmental factors relate to the efficiency in-use of air and/or water resources in

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[12]Although exact product quality specifications are confidential, interviews with Gulf's refinery manager, G. Docken, indicated that as a result of utilizing butanes to improve octane performance, only about one cubic centimetre of tetraethyl lead per barrel of product is blended into the product stream compared with refining industry standards of three to four c.c.'s per barrel. The butane charge at the Gulf Edmonton refinery averages 10-12 per cent of crude charge (crude charge averages 80,000 barrels per day).

the plant cooling systems and as conveyances for plant wastes. Gulf's new refinery makes extensive use of air as a coolant supplemented by cooled, recycled water. Pollution control systems are reported to have been conceived in conjunction with the design of six main operating units and their respective process unit components in the refinery. Environmental control thus becomes part of the day-to-day operations rather than a downstream cleanup problem, thereby effectively internalizing some of the potential external costs of environmental degradation. Another related factor is that the newer technology permits greater recovery of all readily saleable products from the refining of a barrel of crude. This is achieved by successive reforming and upgrading of product stocks to produce a higher light ends yield (which is consistent with product demand mix characteristics in Western Canada) and limiting by-products production to petroleum coke and limited amounts of sulphur.[13]

The second group of environmental factors relates to petroleum products end-use characteristics. Although a host of possible effects could be considered here, one of central concern is pollution from automobile exhaust. Scientific investigations have indicated that in addition to carbon monoxide emissions, the presence of residual non-degradeable substances such

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[13] Sulphur output of the new Gulf Edmonton plant is about 40 long tons per day which is less than sulphur production at the original Gulf Edmonton refinery. Petroleum coke production can be as high as 430 tons per day with a market value of about \$10.10 to \$12.00 per ton. Coke is delivered by rail to Alcan's Kitimat, B.C. smelter for use as electrodes in aluminum smelting.

as lead compounds in the atmosphere are cause for serious concern. Other research has established that more readily combustible additives such as butanes can successfully be substituted to improve octane performance of gasolines thereby considerably lowering amounts of lethal lead compounds entering the atmosphere through automobile exhaust.

Petroleum Products Distribution Systems

The development of petroleum products pipeline transportation systems is proposed as being the requisite necessary condition for further consolidation of refining activity in the western prairie provinces. Examination of this condition further implies an interdependent set of conditions necessary for products pipeline development. This part of the chapter identifies such conditions and recapitulates the importance of two emergent products distribution systems described in chapter two of the study. Conditions for development of products pipelines are discussed under the general headings of market characteristics, products pipeline technology and finally products pipeline costs.

Market Characteristics

A homogeneous product demand mix is required in the region to be served by a consolidated refining operation and a products pipeline distribution system. Reference to Tables 19 and 20 earlier in this chapter reveals that the greatest proportions of product demands (ie. inferred demands from refinery output mixes) are for the so-called lighter ends and middle distillates. These are products such as butanes, propanes, motor gasolines including tractor fuels, aviation turbo fuels, kerosenes and naptha-based jet fuels, diesel and light fuel oils. This pattern of demand contrasts

with that of British Columbia which has fairly significant levels of refinery production over the entire product range. Note in Table 20 the substantial demand for heavy fuel oil or "Bunker C" product in B.C., presumably for use in production of asphalts and also as a marine fuel. Ontario also has a similar diversified composition of demand with additional emphasis on domestic fuel oils, petrochemical feeds and aviation fuels (not shown in Table 20). Both Alberta's and, to a lesser extent, British Columbia's requirements for fuel oil are affected by the availability of natural gas for domestic heating while the use of natural gas in Ontario is concentrated largely in the industrial, power and commercial sectors.

The data indicates that Saskatchewan, Manitoba and Alberta have a fairly homogeneous product demand mix comprised mainly of the lighter ends. Except for asphalt, cokes and some of the heavier fuel oils, the majority of the products can be transported in a products pipeline. Also, Table 21 indicates that the long term trend in U.S. production in response to consumptive demands has been toward the lighter ends which are more amenable to product pipeline distribution.

Several other market characteristics deserve brief consideration. One is that the main prairie markets for petroleum products (ie. Edmonton, Calgary, Regina, Saskatoon, Moose Jaw and Winnipeg) or equivalently the historical prairie distribution centres, are located along lineal, east-west transportation axes. The axes are comprised of trans-Canada Highways, one or other of the national railway lines, and the major oil and gas trunk pipelines. If prairie market concentrations were widely dispersed, pipeline transportation of products would probably not be feasible unless the

TABLE 21

REFINERY PRODUCT
SHIFTS IN YIELD
ON CRUDE OIL, 1945-1965
U. S.

	1945	1955 (per cent)	1965
Gasoline	40.5	44.0	44.9
Distillate fuels	19.1	26.1	29.0
Lubricants and other	13.0	14.5	29.0
Residual Fuel Oil	27.2	15.3	8.1

Source: United States, National Petroleum Council, Impact of New Technology on the U.S. Petroleum Industry, (Washington, D. C.: National Petroleum Council, 1967), p. 257.

absolute market size substantially increased. Certainly in Saskatchewan, which experienced an absolute decline in population according to Statistics Canada's 1971 census, petroleum products markets are not likely to expand sufficient to shift the existing geographical concentration. Most of the main prairie-marketing and distribution points are favourably located with respect to possible service from products lines. The points are Calgary, Edmonton, Saskatoon, Regina, Moose Jaw and Winnipeg.

There also remains a problem of demands in the region for the heavier ends such as road asphalts. It is noted that while Gulf Oil's Calgary refinery has curtailed all of its refined products production, asphalt production has been retained. Should other major refiners decide to close plants in the above mentioned centres in favour of a consolidated refining operation in Edmonton, local demands for the heavier ends in these areas might require partial continuation of their production since they cannot be shipped by pipeline. Other competing modes such as rail or truck could conceivably carry these lower value, high bulk products, although transport costs of the other modes would have to be weighed against on-site plant production costs for, say, asphalts to determine the feasibility of continuing heavy ends refining versus complete consolidation and relocation. Yet another possibility is for the only exclusive heavy ends refiner in Saskatchewan, Husky Oil Limited at Moose Jaw processing the heavier Saskachewan crudes, to increase its plant capacity sufficient to meet demands created by the curtailment of other heavy ends refining in the Province.

Saskatchewan and Manitoba also have a fairly significant demand for LPG's, specifically propane, which the Interprovincial Pipe Line Company does not carry due to this product's volatility. Propane and other LPG's

are carried, however, by rail tank car from Edmonton to eastern Canada and by pipeline (Petroleum Transmission Company) from the Dome-Amoco, Empress, Alberta gas and fractionation plants to prairie distribution points as far east as Winnipeg.

Products Pipeline Technology

Very little has to be added here to discussions in chapter two on products line technology accept to recapitulate the essential differences between petroleum products and crude petroleum pipelines. These differences are likely to become increasingly less significant, though, as will be pointed out.

Briefly, exclusive products systems differ from their crude oil counterparts in the following areas:

a. Products systems have higher safety specifications due to greater combustibility, volatility, etc., of the products carried.

b. Throughput volumes for particular products are substantially lower than typical batches of crude. This also requires more elaborate dispatching facilities in order for the products line to be efficiently utilized. Crude lines are typically of larger diameter.

c. In-line stream monitoring, batch separation and interface detection equipment are more sophisticated since product quality must be preserved. (eg. no loss in quality of diesel fuel would result if traces of motor gasoline co-mingled at the interface with the diesel fuel but if the reverse occurred, a serious quality problem would result. Partial co-mingling between different quality crudes is, by contrast, an inconsequential quality problem).

d. Products lines are more susceptible to corrosion problems and the related problem of product cleanliness. This problem is mitigated by periodic "pigging" (ie. internal scraping) or by internal coating during construction.

e. Pumping rates for products are only slightly affected by temperature and viscosity whereas crude oil temperatures and viscosities substantially affect pumping efficiency.[14]

The most important point to be gleaned from examination of literature sources and interviews with industry spokesmen[15] with respect to the status of pipeline technology in western Canada is that petroleum products can be efficiently transported given sufficient throughput volumes; the most crucial problems, eg. batch separation, quality and safety controls, can be minimized with presently available technology.

Costs of Products Pipelines

Inspection of the tariff data presented in chapter three reveals that transportation costs on refined and other petroleum products such as gas liquids (excluding LPG) ranges from five to ten per cent higher than per barrel tariffs on crude oil between equivalent points. This implies an underlying cost structure of products lines not substantially different from crude oil lines except in respect to fixed/operating cost ratios. In products lines the ratio was shown to be 70:30 approximately while for crude oil lines it was 60:40 (see Table 1). The differential is explained in large part by higher initial investments for products line control equipment. There are some difficulties, however, in drawing this inference from

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[14]U. S., National Petroleum Council, Impact of New Technology, p. 224.

[15]The sources include U.S. National Petroleum Council, op. cit.; Denton, W., "Pipelines offer least costly transportation means", Oil and Gas Journal, (August 6, 1968); and M. Dimentberg, "Better economics promise eventual use of LNG lines", Oil and Gas Journal, (Sept. 18, 1967); O.T. Linten, Interprovincial Pipe Line Company (June 9, 1972), Interview; and G.C. Docken, Gulf Oil Canada Ltd., Interview, (various dates).

observation of actual installation costs for current crude and products line construction programs.[16] Diameter inch mile cost differentials as between different crude line projects and between product and crude lines are explained by differences in transport costs of materials, access and right-of-way acquisition costs, etc. Rule-of-thumb estimates of initial cost for either type of pipeline system are therefore particularly hazardous.

With respect to intermodel cost comparisons, between, say, pipeline, rail tank car and truck, the most important considerations in determining the feasibility of pipeline service are market size (and consequent throughput), dispersion of markets and distance. Trucking of petroleum products appears to be feasible in a dispersed market within a threshold radius from the distribution point up to about 200 miles. This may be considered local distribution. Refined products pipelines from Edmonton to Calgary (193 miles), Edmonton to Saskatoon (350 miles), and Edmonton to Regina and Moose Jaw (438 miles) are presently favored over other modes beyond the 200 mile threshold radius where the previously cited market size, homogeneity and locational conditions hold.[17]

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[16]Alberta Products Pipe Line between Edmonton and Calgary costed approximately $7 million or $3500 per diameter inch mile. Some larger diameter products lines in the U.S. have cost as much as $7000 per diameter inch mile. Interprovincial Pipe Line's current 48 inch looping program in Canada has been estimated to cost $7300 per diameter inch mile. Periodic pipeline construction cost data is given in The Oil and Gas Journal's Annual Pipeline Number (usually September or October issue).

[17]Spot checks on truck and rail tank car rates for LPG (the only light petroleum product shipped by rail) revealed the following:

Propane by tank car to Vancouver	$ .70 per barrel
Propane by tank car to Clarkson, Ont.	$2.10 per barrel
Propane by truck-radius 100 miles	$ .40 per barrel

Source: G. C. Docken, Gulf Oil Canada Ltd., Edmonton

Applications to Gas Liquids Fractionation Plants

As has been mentioned in earlier chapters, processing plants are located close to gas fields where the raw gas stream is rendered into marketable natural gas comprised mainly of methane and natural gas liquids (a blend of propane, butane and pentanes 'plus' or other condensates). Fractionation, the process which further splits the gas liquids into LPG's, principally propanes and butanes, has been oriented both to markets and field sources. Much of the fractionation capacity in western Canada is in conjunction with refinery operation. In eastern Canada, fractionation plants are located near the major crude oil refining and petrochemical complexes at Sarnia and Montreal. A few notable cases in Alberta have fractionation plants directly associated with gas processing plants. In these cases, an LPG pipeline exists to connect the plant to refinery gates in Alberta or to propane storage and distribution sites. Still, fractionation remains largely a market oriented activity.

Unfortunately, the complexity of introducing natural gas related activities in the present study would be well beyond its intended scope, but it is useful to briefly mention a few factors analogous to the above discussions on refined products pipelining and processing location. The main products of fractionation, propane and butane, are presently being pipelined across the three prairie provinces and also from field plants to refinery gates within Alberta. Propanes are transported to storage and distribution points and butanes to refineries in the Regina and Winnipeg areas. Quite clearly, if market size warrants further development of LPG pipelines, this mode is the most efficient means of distribution (see footnote 17 for cost

comparisons) but at the present time, markets in the three provinces for propane are limited by the costs and potential uses of competitive fuels such as natural gas and for butane by the status of technology in the existing refineries.

The availability of LPG pipelines, though, is not likely to directly affect the geographical orientation of fractionation processing. However, with tariffs on LPG pipeline movements not likely to be significantly more than that on NGL (the unfractionated blend), probable further refining consolidation in Edmonton with related increased requirements for field butanes is expected to become a highly important influence on the location of additional fractionation capacity.

CHAPTER FIVE

CONCLUSIONS

This study has been concerned with evolving and applying an analytic framework in which to examine a contemporary phenomenon in western Canada, the consolidation of prairie refining in Edmonton and the distribution of petroleum products, particularly refined products, by products pipelines. The present chapter contains the main conclusions of the analysis. Implications stemming from these conclusions are also presented. Finally, limitations of the analysis and possible research extensions are indicated.

Summary

Introductory material in chapters one and two showed that pipeline systems are a highly important segment of the petroleum industry in Canada. In fact, in the absence of petroleum gathering and trunk pipelines, development of western Canada's petroleum resources simply would not have taken place. Discussion of typical petroleum liquids pipeline system components preceded identification and discussion of the major operating lines originating in the Province of Alberta. Liquids systems components were shown to be comprised of storage tanks (both receiving and terminal), pumping equipment, control units and the line pipe itself. Some detail was provided with respect to the status of technology in respect to pipeline system components. Developments include control technology and batch separation technology. By comparison, and in order to complete discussion of petroleum pipeline system components, natural gas pipelines were described. Next, major crude oil pipelines originating in the Province of Alberta including

both gathering and trunk systems were described; this included capacity estimates, and identification of crude sources and market destinations. The major processed products (natural gas liquids and liquified petroleum gases) and refined products pipeline systems in Canada were also described. Pipelines of particular interest in this study are the products systems operated by the Interprovincial Pipe Line Company between Edmonton, prairie terminals and points in eastern Canada and the U.S., and that operated by Alberta Products Pipe Line Company (operated by Gulf Oil Canada and owned by Gulf, Imperial, Shell and Texaco) between Edmonton and Calgary serving southern Alberta and southeastern British Columbia markets. Gas liquids (NGL and LPG) systems were also described with emphasis on the regional nature of the markets for LPG and the NGL line transmission capacity to refining centres such as Sarnia.

Chapter three focused on evolving an analytic framework within which to view regional consolidation of refining and processing of petroleums. The cost structure of the pipeline industry was seen to be comprised of static cost factors such as variable and fixed cost components and innumerable interrelated cost parameters affecting the variable or operating to fixed cost ratio. The intermediate run (horsepower variable, diameter fixed) optimal pipeline production problem was demonstrated in terms of a simplified two-factor, conventional constrained cost minimization problem.

A second highly important constituent of pipeline cost structure is the nature of long run costs and specifically the nature of economies of scale. Intermediate run characteristics of variable application of horsepower apply in the long run as well as the fact that pipe diameter can be varied by looping or laying other lines. Empirical evidence given in the

chapter indicates there are substantial economies of scale to be realized in the pipelining of petroleum due largely to technological characteristics of pipelines. One possible measure of scale economies through the econometric estimation of a scale coefficient was given.

Chapter three also provided analytical linkages between the derived cost structure of pipeline operation and actual realized transportation costs for crude petroleum and petroleum products to various market destinations. An accounting method of determination of pipeline rate base, upon which tariffs are established to earn specified rates of return, was examined and related to the previously derived cost structure. The structure of pipeline tariffs, shown to increase less than proportionately with distance, was explained in terms of cost structure of the industry. Overall transportation costs of petroleums were also shown to comprise a significant proportion of delivered prices of crude oil and petroleum products in various markets and as such, represented a highly significant factor in the competitiveness of Alberta petroleums. As markets for crude petroleums and petroleum products improve and pipeline system capacity increases, transport cost savings expected as a result of realized declining long run costs will be reflected in lower delivered prices (or higher wellhead prices in the case of crude oil) and consequent improvement in the competitive position of the Province's petroleum and products.

The final part of chapter three introduced the economic determinants of refinery location. The most important factors were identified as transport costs on raw materials relative to that on finished products, the nature and distribution of markets served by the refining complex, and attainable economies of scale in refining consolidation. As with pipelines, there

appear to be moderate economies of scale attainable in various refining unit operations based on econometric estimation of the scale coefficient from cross-sectional data.

Conclusions

It is from chapter four, application of the analytic framework, that most of the conclusions of this study evolve. The chapter presented necessary and sufficient conditions for regional consolidation of refining in the prairie provinces. Sufficient conditions for consolidation, based on observation of Gulf Oil Canada's new Edmonton refinery, were identified to be the magnitude of operating cost savings of larger process units (economies of scale), availability and proximity of raw materials, the status of refinery technology and several environmental factors related to plant technology. The following inferences can be made about these conditions:

a. Real and monetary economies of scale must be positive and the resulting direct processing cost at the new refinery must be lower than the costs of operation and closure of the older plants.

b. Raw materials orientation of prairie refining including the proximity of field butane supplies and assured long term supplies of crude oil is likely to become an increasingly important influence on the location of refining.

c. The dynamic nature of refining technology embodying, for example, more efficient catalysts and processes, has combined with efficiencies of size to increase the potential magnitude of cost savings from consolidation and enlargement of the individual plants refining capacity.

d. Environmental externalities such as pollution have imposed in-plant technological modifications bearing on plant environmental resources use and product quality.

A set of factors relating to available transportation systems were shown to comprise necessary conditions for regional refining consolidation. These factors are the availability of an efficient products pipeline distribution network and related necessary factors of regional product demand homogeneity, availability of control technology and most important, minimum competitive transportation costs (ie. pipeline tariffs). The following inferences can be drawn from these necessary conditions:

e. Products pipeline systems now exist in the prairie region to distribute refined product and processed product to key market distribution points at Calgary, Regina, Saskatoon and Winnipeg.

f. The prairie region has a relatively homogeneous product demand mix which can easily be distributed through the pipeline systems.

g. Products pipeline transportation costs as embodied in tariff structures on refined and processed products are at most five to ten percent higher than the equivalent per barrel tariff on crude oil and condensate. Transport costs by pipeline are substantially lower than alternative modes such as truck and rail tank car although these modes are important in serving either spot markets or local markets.

The existence of these six coincidental factors will probably affect a very important reorientation of prairie refining and processing from activity originally dispersed throughout the region with crude supply distribution by crude pipeline to activity seemingly approaching consolidation within one province.

Implications

Construction of Imperial Oil's 140,000 barrel per day Strathcona refinery in Edmonton is indicative of the strength of the factors bearing on refining consolidation evaluated in this study. Of a total estimated

prairie refining capacity of 266,000 barrels per day, Imperial Oil presently accounts for approximately 102,000 barrels per day or about 38 percent and with the completion of the new plant in 1974 this share will increase somewhat. The full extent of consolidation through closure of the company's other plants is difficult to determine at the present time but it seems highly likely that at least the Regina and Calgary operations would be phased out since products distribution systems are available to serve these areas and all of the requisite conditions for consolidation identified in this study are present. Closure of the Winnipeg refinery would also seem to be implied since refined product could be transported through Interprovincial's product line to Gretna, Manitoba and thence into Imperial's 10 inch line to Winnipeg once the latter line has been modified.

Partnership of the four major integrated oil companies (Gulf, Shell, Texaco and Imperial) in the Alberta Products Pipe Line between Edmonton and Calgary is also indicative of substantial interest in further consolidation of prairie refining activity in the Edmonton area. Shell presently operates an older 26,500 barrel per day plant (1927) at St. Boniface and a smaller 5,000 barrel per day unit (1960) at Bowden while Texaco operates only one 20,000 barrel per day refinery (1951) at Edmonton. Other refiners such as Husky Oil, Northern Petroleum and Consumers Cooperative comprise only a very limited proportion of prairie refining capacity and product markets.

Sections of the study have also examined gas liquids (LPG and NGL) pipelining and the related location of fractionation plants. Generally speaking, these plants are drawn towards major market areas for propane, butane and pentanes 'plus'. Dome Petroleum's gas liquids gathering systems

feed into the Interprovincial system to Sarnia and other eastern points where substantial fractionation capacity exists. However, if LPG lines develop with transport costs competitive with other modes and at rates not significantly higher than unfractionated product (as would seem to be indicated by the preceeding analysis) the location of new plants could conceivably be oriented more towards the source of raw materials, ie. Alberta gas fields and processing plants or near major Alberta refining centres such as Edmonton. A related factor possibly reinforcing this orientation would be significant increases in the demand for LPG (specifically butane) should further refinery consolidation be realized.

Another implication of the study concerns the potential capacity utilization of existing cross-country crude oil pipelines for products pipelining. Although the study has not specifically examined this problem, it seems rather unlikely that crude oil pipeline capacity to eastern Canada and United States points would not be fully utilized even under the most speculative assumption of complete prairie refining consolidation in Edmonton. Even if consolidation were complete, the study has shown that very little volume and hence revenue loss would result since the existing products system of the major carrier in question (Interprovincial Pipe Line Company) would be used to distribute products to regional market points. Whether existing interprovincial product line capacity would be sufficient under conditions of further consolidation is another very important further consideration but beyond the scope of this study.

Limitations of the Analysis and Research Extensions

The weaknesses of the analysis are in areas of quantitative estimation

of some of the factors identified as being pertinent to products line development and refinery consolidation. Unfortunately, very little up-to-date cost data for pipeline operation was available; had cross-sectional cost data from different size pipeline system operations been obtained, actual estimates of potential scale economies could have been derived. This limitation is also noted in the case of estimation of potential scale economies from refining. Published studies of these industries did show, however, that both had potential for increasing returns.

Other factors cited but lacking quantitative support related to environmental resources. It would clearly have been useful to derive estimates of cost (or savings) of some of the technological modifications required resulting from more efficient in-plant use of environmental resources and utilizing non-lead additives.

Several very important research extensions would seem to be apparent if the trends implied in this study are realized. One is that consolidation may seriously contribute to gradual erosion of the primary manufacturing and secondary industrial employment bases of Manitoba and Saskatchewan. Sound interregional employment policies providing for realistic mobility opportunities and the need for co-operative attitudes of the province likely to accrue most of the benefits of consolidation are clearly indicated.

A second possible research extension is that with the prospect for greater processing of a portion of the petroleum resource within the Province of Alberta, a study of potential for expansion of the existing petrochemicals industry might be warranted.

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